S. HRG. 98-774

RECOVERY OF OIL BY MINING

HEARING

BEFORE THE

SUBCOMMITTEE ON
ENERGY AND MINERAL RESOURCES

OF THE

COMMITTEE ON
ENERGY AND NATURAL RESOURCES
UNITED STATES SENATE

NINETY-EIGHTH CONGRESS

SECOND SESSION

ON THE

RECOVERY OF OIL BY MINING

MARCH 2, 1984

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RECOVERY OF OIL BY MINING

FRIDAY, MARCH 2, 1984

U.S. SENATE,
SUBCOMMITTEE ON ENERGY AND MINERAL RESOURCES,
COMMITTEE ON ENERGY AND NATURAL RESOURCES,
Washington, D.C.

The subcommittee met, pursuant to notice, at 10:05 a.m., in room SD-366, Dirksen Office Building, Hon. John Warner presiding.

Present: Senator Warner.

Also present: Robert L. Terrell, professional staff member; and Linda Mason, professional staff member for the minority.

OPENING STATEMENT OF HON. JOHN W. WARNER, A U.S. SENATOR FROM THE STATE OF VIRGINIA

Senator WARNER. Come to order. I understand there is time constraint on certain witnesses. To accommodate their schedules, the Chair will forgo reading an opening statement and we will proceed directly to the panel.

[The prepared statement of Senator Warner follows:]

OPENING STATEMENT
BY
SENATOR JOHN W. WARNER
AT THE
OVERSIGHT HEARING
ON
"RECOVERY OF OIL BY MINING"
March 2, 1984
9:30 A.M.

GOOD MORNING. THE SUBCOMMITTEE WILL HEAR TESTIMONY THIS MORNING ON RECOVERING OIL IN THE UNITED STATES BY USING VARIOUS MINING TECHNIQUES. THE WITNESSES APPEARING BEFORE US TODAY REPRESENT A GOOD CROSS-SECTION OF EXPERTISE AND INTEREST IN THIS AREA.

AS MOST OF MY COLLEAGUES ARE AWARE, CONVENTIONAL OIL RECOVERY TODAY CONSISTS OF THE PRIMARY, SECONDARY, AND TERTIARY METHODS. RECOVERING OIL BY MINING HAS BEEN REFERRED TO AS THE FOURTH METHOD OR "QUATERNARY" METHOD. WHILE THE LATTER HAS NOT BEEN AGGRESSIVELY PURSUED IN THIS COUNTRY, IT IS BY NO MEANS A NEW METHOD.

AS A MATTER OF FACT, OIL MINING FIRST TOOK PLACE IN THE SINAI PENINSULA, THE VALLEY OF THE EUPHRATES, AND IN PERSIA PRIOR TO 5000 B.C. MANY FOREIGN COUNTRIES HAVE INVESTIGATED AND CONDUCTED SUCCESSFUL MINING OPERATIONS FOR OIL. GERMANY, FOR EXAMPLE, ATTEMPTED TO INCREASE ITS SUPPLIES OF OIL BY UNDERGROUND MINING METHODS DURING WORLD WAR I (1914-1918). IN 1935, GERMAN OIL MINING WAS CARRIED OUT ON A MORE COMMERCIAL BASIS. FOR MANY YEARS, FRANCE SUCCESSFULLY AND ECONOMICALLY RECOVERED OIL BY MINING ZONES THAT WOULD NOT PRODUCE BY CONVENTIONAL WELLS. THE SOVIET UNION UNDERTOOK MINING OF THE YAREGA FIELD WITH SUBSEQUENT PRODUCTION OF 1.5 MILLION BARRELS ANNUALLY.

WHILE THERE HAVE BEEN SUCCESSFUL EXPERIENCES ABROAD IN RECOVERING OIL BY UNDERGROUND MINING METHODS, VERY LITTLE HAS BEEN ACCOMPLISHED IN THE UNITED STATES. IT IS NOT AS THOUGH WE HAVE NOT LOOKED INTO THE RECOVERY

OF OIL BY MINING -- WE HAVE. THERE HAVE BEEN STUDIES, REPORTS, ARTICLES IN PROFESSIONAL JOURNALS, ETC. PREPARED BY GOVERNMENT, INDUSTRY, AND INDIVIDUAL PROFESSIONALS AS FAR BACK AS 1932. HOWEVER, THERE HAS BEEN LITTLE OR NO PRACTICAL APPLICATION OF WHAT WE'VE LEARNED.

IT IS INTERESTING TO NOTE THAT, USING PRIMARY, SECONDARY AND TERTIARY RECOVERY METHODS, WE ONLY ACHIEVE 32% RECOVERY FOR CONVENTIONAL LIGHT CRUDE AND UP TO 25% RECOVERY FOR HEAVY OR VISCOUS CRUDE. THAT TRANSLATES INTO 68% AND 75% RESPECTIVELY OF CRUDE RESERVES LEFT IN THE GROUND. PUT ANOTHER WAY, THERE IS AN ESTIMATED 300 BILLION BARRELS OF CONVENTIONAL LIGHT CRUDES AND ANOTHER 200 +/- BILLION BARRELS OF HEAVY OR VISCOUS OIL AND TAR SANDS CONSIDERED TO BE UNRECOVERABLE RESERVES. HOWEVER, WE ARE TOLD THAT UP TO 95% OF THESE SO-CALLED UNRECOVERABLE RESERVES COULD BE RECOVERED USING VARIOUS MINING TECHNIQUES. I FIND THIS POTENTIAL TO BE ASTONISHING, IN LIGHT OF WHERE THIS COUNTRY FINDS ITSELF WITH RESPECT TO IMPORTED OPEC OIL AND OUR DISCOURAGING EFFORTS IN DEVELOPMENT OF SYNTHETIC FUELS.

I LOOK FORWARD TO LEARNING MORE ABOUT THE PROSPECTS OF MINING OIL FROM THE DISTINGUISHED LINE-UP OF WITNESSES TODAY. YOU CAN BE SURE THAT I WILL NOT ONLY FOLLOW THE DEVELOPMENT OF THIS VERY PROMISING TECHNOLOGY, BUT I WILL ASSIST IN ANY WAY THAT I CAN IN BRINGING IT INTO FRUITION.

Senator WARNER. Gentlemen, the reporter has your names. You may proceed. You may lead off with your testimony, Mr. Burlingame.

STATEMENT OF JAMES M. BURLINGAME, DIRECTOR, PETROLEUM MINING CORP.; ACCOMPANIED BY JEFFREY A. MILLER, PRESIDENT, PETROLEUM MINING CORP.; AND VINTON A. GARBESI, VICE PRESIDENT, S&M CONSTRUCTORS, INC.

Mr. BURLINGAME. I am James Burlingame, attorney at law in New Orleans. I am a director of Petroleum Mining Corp. To my immediate left is Mr. Jeffrey Miller, who is president of Petroleum Mining Corp., and to his left is Mr. Vinton Garbesi, who is vice president of S&M Constructors, Inc., Solon, Ohio.

Our testimony, Senator, I think, sets forth the program of the Petroleum Mining Corp. and S&M in a joint venture. We are proposing to drill an oil mine, if you will, in Caddo Parish, La. The construction is essentially a 48-inch hole in the ground. Below the base is Annona chalk some 1,600 feet down. We will drill lateral tunnels out from that roughly 10 by 10. Every 50 feet we will be drilling alcoves from which oil wells, if you will, will radiate out. They will be on about 50-foot centers.

They will initially produce close to 100 barrels a day. Production will very rapidly decline to roughly 1 barrel a day.

Senator WARNER. Over what period?

Mr. BURLINGAME. The decline, in probably about 3 months, a very rapid decline, per hole that is. On this 80-acre tract or unit that we will be drilling on, there will be ultimately some 1,500 holes and on 50-foot centers there is great density.

The technology is not particularly new. It has been used in France and in Russia, and Japan used it during the war. The Germans mined a great deal of their oil during the war with the same technique. It is unique to the United States. The Annona chalk formation in Caddo Parish has been handled by our experts.

There are two fields in the United States that are primarily adaptable to this type of operating. We are the second best. The best is in Kern Field in California. But the density of the oil there is so great that it will not gravitate as this will. The field in which we are operating has roughly 140,000 some odd barrels per acre. Less than 10 percent of it has been produced now. Production has been in being since about 1970.

They say that this technique will produce somewhere between 30 and 50 percent of the entire field. The techniques that we are going to use for extraction of the oil are not particularly unique in that they used this type of drilling to extract methane and gas in the coal fields.

Our experts, Lloyd Elkins, who is our engineer, has given us the opinions that are reflected in the exhibits to our testimony. Our mining contractor has been Mr. McCarthy of McCarthy Drilling and S&M Constructors, our partner, is now taking over that function.

The exhibits may be somewhat misleading in that they describe Logans tract which is immediately south of our operation. For reason of landownership, we have to adjust the unit to make it go

in an east/west direction to reflect the unit that we have. Because of the uniqueness of the operation the Louisiana Department of Conservation asked us to apply for a permit, which is a pretty perfunctory thing in Louisiana, to hold a hearing so that they could have the technique described to them.

We did, and I might add, we had a great deal of cooperation from their staff. As a result of the hearing, we were issued an order which authorized the issuance of the permits. The projected plan is to drill 100 holes, test the technique and see that it works, and have it demonstrated that it works and the balance of the 1,500 holes will be drilled.

We expect to begin operation in the very immediate future and we would like to talk to you all after we have done it and to teil you it works.

[The prepared statement of Mr. Burlingame follows:]

TESTIMONY OF

JAMES M. BURLINGAME AND JEFFREY A. MILLER

BEFORE THE SUBCOMMITTEE ON ENERGY AND MINERAL RESOURCES

OF THE

COMMITTEE ON ENERGY AND NATURAL RESOURCES

OF THE

UNITED STATES SENATE

Gentlemen:

I am James M. Burlingame, Attorney at Law, a Senior Partner in the firm of Jones, Walker, Waechter, Poitevent, Carrere & Denegre in New Orleans, Louisiana, and member of the Board of Directors of Petroleum Mining Corporation. May I introduce to you Mr. Jeffrey A. Miller, President and also a member of the Board of Directors of Petroleum Mining Corporation.

In the immediate future, Petroleum Mining Corporation, a corporation whose principal offices are Suite 250, 336 Camp Street, New Orleans, Louisiana 70130, (which shall be referred to hereinafter as PMC) and its co-venturer, S & M Constructors, Inc. of Solon Ohio, intend to commence operations for an oil mine in the Caddo/Pine Island Field, Caddo Parish, Louisiana under an 80 acre unit known as the Petroleum Mining Corporation-Lane/Crye Voluntary Unit A. In an oversimplification, this oil mine will consist of a 4' in diameter main shaft to be drilled to a depth immediately below the soft limestone Annona Chalk formation or approximately 1,600' to 1,700' below the surface of the earth; several ventilation shafts to provide sufficient air throughout the operations; utility shafts through which production will be brought to the surface; and lateral tunnels some 10' x 10' in size driven from the main shaft to the perimeter of the unit. At approximately fifty foot intervals along each of these lateral tunnels, 20' x 20' "drilling stations" or alcoves will be excavated from the shale. From these drilling stations, small

diameter 4" drainage holes will radiate upwards into the Annona Chalk formation in order to achieve a corresponding spacing of approximately 50' between the drainage holes. A diagram which illustrates these "oil mining" techniques is attached hereto as Exhibit "A".

The small hole drilling technique is widely used throughout the deep coal mines of the eastern seaboard of the United States as a means of removing methane. Inasmuch as this technique is novel in this part of the country if not this part of the world for producing oil, the project will initially consist of 100 or less drainage holes to determine whether or not the project produces oil commensurate with the expectations set forth in our engineer's reports. Assuming that the project is successful, an additional 1,400 holes will be drilled on the 80 acre unit. The Petroleum Mining Corporation-Lane/Crye Voluntary Unit A, the shafts to be drilled and the first 100 wells are depicted on the plat attached hereto as Exhibit "B".

Although novel to us, "oil mining" is by no means a new technology. The ancient Egyptians mined oil seeps and used the ooze in their embalming fluids. The French mined oil in the 18th century and again in the first half of this century at the Pechelbronn Field in the Alsace Region. During World War II the Germans obtained nearly a quarter of their oil from mines under the Wietze Field near Hanover and the Japanese were able to

produce oil from mines in Higashiyama. A notable example of oil mining today is under the Yarega Field in the Soviet Union. The Russians were able to produce 972,010 barrels per year at a cost estimated in 1976 at $5.29 per barrel. In 1981 they reported production of 1.5 million barrels annually and plan to increase production to 6.7 million barrels.

PMC proposes to use drilling technologies developed by the U.S. Atomic Energy Commission to drive the large diameter hole. The lateral tunnels will be driven using standard mining methods. These tunnels will run for varying lengths.

The oil will be produced initially by a combination of gravity drainage and drainage reservoir pressures (gas, oil and water) and in due course this will be augmented by steam and/or gas injection. After the oil is pumped to the surface, it will be stored in tanks. The gas produced ancillary to the production of oil will be sold.

Pine Island is in the center of an oil producing area located in the northwestern corner of the State of Louisiana. Oil was discovered in Pine Island in 1905. In excess of 16,000 wells have been drilled in this field since its discovery and the current average daily rate of production per well is 1 barrel per day. Still, however, it has been estimated that less than 10% of

the original oil in place at Pine Island has been recovered. Such low proportion of the original oil in place has been recovered due to the fact that the Annona Chalk formation is one of very low permeability. As mentioned, this chalk formation lies at a relatively shallow depth of less than 2,000'. Numerous attempts have been made to enhance recovery of this oil by using various methods including acidization, fracturing by all known methods, water flooding and sonic stimulation. None of these attempts have been spectacularly successful.

Experts have suggested three primary considerations in selecting a field for oil mining: first, ample oil reserves in place; second, excellent subsurface conditions for mining; and, third, a ready market for the oil. Largely because PMC believes that in the Pine Island Field all three of these criteria are satisfied, PMC selected it as the site for its Project. In fact, a computer analysis run by Mr. Lloyd E. Elkins of Tulsa, Oklahoma, a world-renowned petroleum engineer, during his study of the Field for the Department of Energy showed it to be the oil formation in the United States which was second most amenable to a mining type operation. The Kern Field, in California, which the computer analysis indicated to be the most amenable field, although it has a shallower depth and more oil in place than the Pine Island Field, would be more difficult to produce from since, due to the heaviness of its oil, mere mining would be unsuccessful and steam would have to be induced.

Additionally, lease availability influenced PMC's choice of Pine Island Field as the site for its Project. PMC's rights in this area stem from assignments from C.L. Morris, Inc. and from a sublease of leasehold rights from Texaco, Inc.

During 1982 and 1983 Mr. Elkins carried out an analysis of the oil producing rates and ultimate recovery of all reserves in place which could be expected in the project. Mr. Elkins' investigation revealed that only 5% of the oil in place and in the project area has been produced and that there is sufficient oil in place to justify the application of the oil mining techniques discussed herein. He concluded the geological characteristics of Pine Island are such that the application of primary/secondary sources of energy will produce crude oil at rates expected to make the mining-drain hole production methods economical. It is his belief that after six years of production approximately 30% of the oil in place can be recovered through the mining project. A report delivered to the Directors of PMC's parent company, Petroleum Mining Company Limited, by Mr. Elkins is attached hereto as Exhibit "C".

From April to June, 1981, PMC's mining consultant, McCarthy Engineering and Construction, Inc. (McCarthy) carried out a feasibility study to evaluate the subsurface conditions of

Pine Island. McCarthy has had wide experience in excavating LPG caverns throughout the United States and of the techniques needed in the mining aspects of the project. This study was carried out on the lease styled the Logan Lease which is located immediately to the south of the western half of the PMC-Lane/Crye Unit, but we have been advised that the characteristics of the Lane/Crye Unit are the same as those of the Logan lease. This study consisted of a review of available geologic records and all available data on the history of oil mining including studies recently made for the U.S. Bureau of Mines Department of Energy, the coring of a hole, logging and describing the cores and collecting samples for laboratory analysis; the preparation of an engineering analysis from the data obtained from field work and laboratory analyses of the cores; and the preparation and review of cost analysis. The principal conclusion of the feasibility study was that its technology is an economically viable means of extracting oil from the Annona Chalk. A copy of McCarthy's short form critique feasibility report addressed to the Directors of Petroleum Mining Company Limited is attached hereto as Exhibit "D". In addition we attach hereto as Exhibit "E-1" a Feasibility Report prepared by McCarthy which was presented to the Office of Conservation, Department of Natural Resources of the State of Louisiana at its hearing with respect to this project held on November 30, 1983 and as Exhibit "E-2", the diagrams and other exhibits introduced therewith.

PMC's geological consultant, Mr. George Hasseltine, testified at the hearing before the Louisiana Office of Conservation discussed below regarding feasibility of this project. He introduced in evidence the well log and core analysis attached hereto as Exhibits "F" and "G", respectively. Mr. Hasseltine concluded that approximately 141,000 barrels of oil per acre were in place in the unit and agreed with Mr. Elkins' conclusion that only about 5% of that total had been produced by conventional means. He also agreed with Mr. Elkins' conclusion that at least 30% of the oil in place could be recovered by "oil mining", but he suggested, further, that as much as 50% might eventually be recovered. According to his calculations, each well would drain .057 acres and recover approximately 1,827 barrels of oil at the 30% recovery rate. At the 50% rate, each well would recover 2,600 barrels of oil.

On August 30, 1983, PMC applied to the Office of Conservation of the Department of Natural Resources of the State of Louisiana to call a hearing to review the proposed mining plan and to cause the issuance of the necessary permits for the drilling of the wells on the unit. The owners of all surface, mineral, royalty and leasehold rights under the 80 acre unitized tract entered into a voluntary agreement pooling their acreage and rights to form the Petroleum Mining Corporation-Lane/Crye Voluntary Unit A. This unit is depicted on Exhibit "B". Prior

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to the filing of the application for hearing and between the filing of said application and the actual hearing itself numerous conferences were held with the Commissioner of Conservation, the Honorable Patrick H. Martin, and the very able members of his staff, including Mr. Joseph W. Hecker and Mr. Freddie J. Boudreaux, whose cooperation greatly aided the preparation of this project. A hearing was held on November 30, 1983 before the Members of the Office of Conservation who, after due consideration, issued an order directing the granting of permits for the operation, a copy of which order is attached hereto as Exhibit "H".

It has been a pleasure appearing before you gentlemen today and we would hope that in the not-too-distant future we would be able to appear before you again to report a successful project and to describe to you new technologies which have been developed as the project progresses.

Thank you--

The following diagram illustrates the "oil mining" techniques which will be utilised and which have been described above –

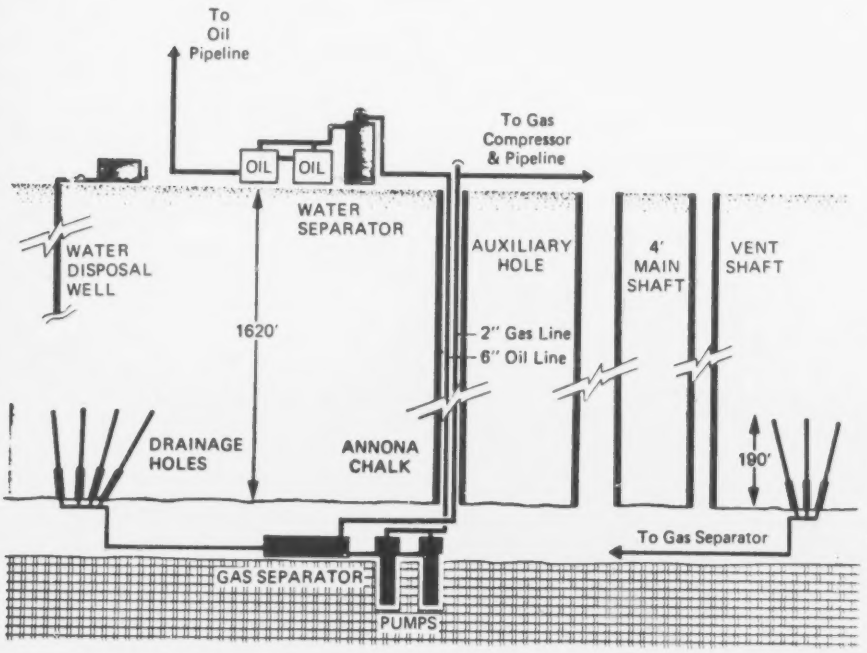

EXHIBIT "A"

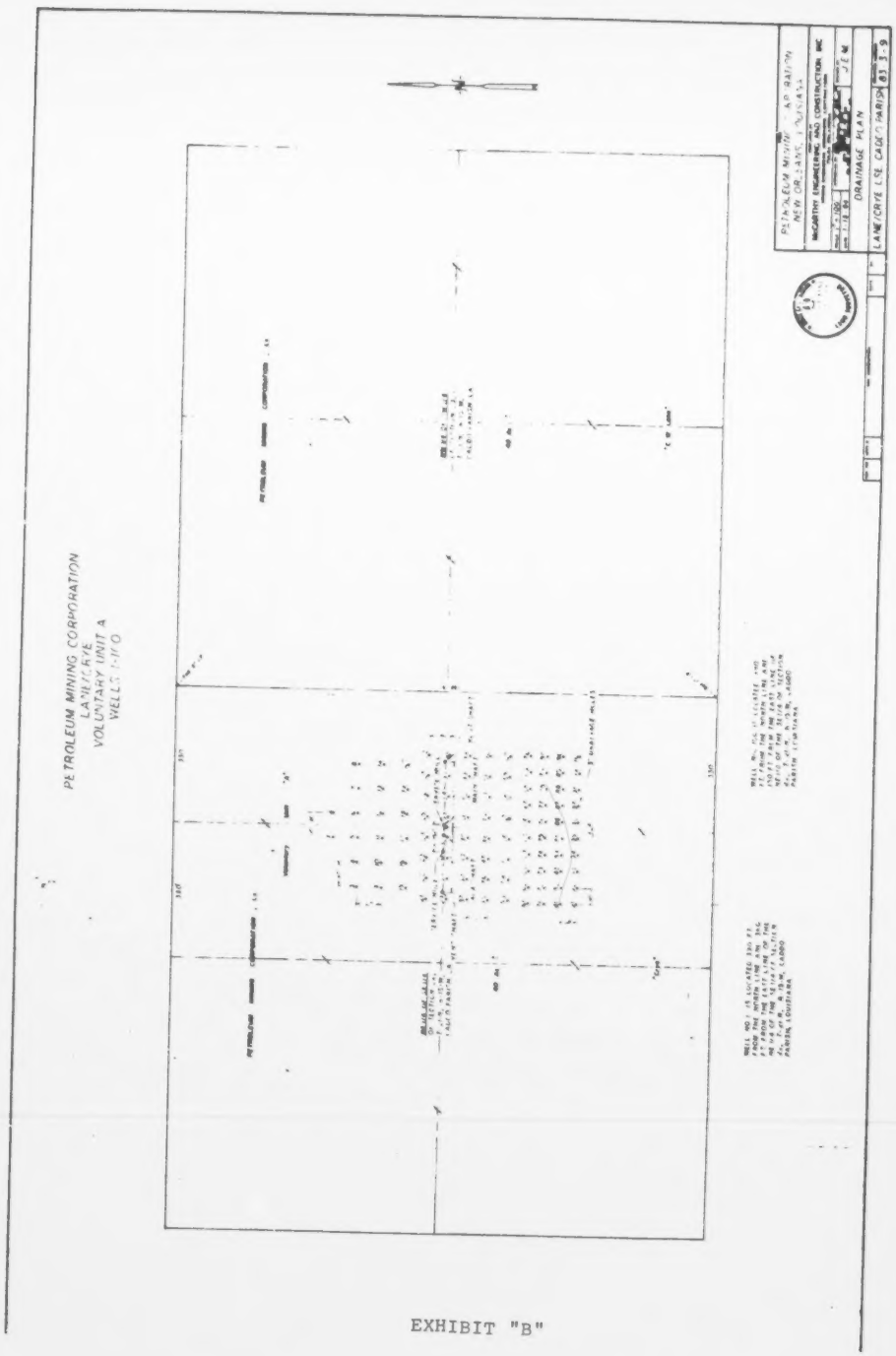
PETROLEUM MINING CORPORATION
LANE/CRYE
VOLUNTARY UNIT A
WELLS INFO
DRAINAGE PLAN

EXHIBIT "B"

The Directors
Petroleum Mining Company Limited
37 Athol Street
Douglas
Isle of Man

PO Box 4758
Tulsa, Oklahoma 74159
USA

31st October 1983

Dear Sirs

Appraisal of the Logan Lease, Pine Island Field, Louisiana

Upon the instructions of Mr William Nathan I have carried out an initial investigation followed by a more in depth study into the oil producing rates and ultimate recovery expected for drain holes at the Pine Island Field mining project. I have submitted two detailed reports dated 7th December 1982 and 18th April 1983 and at your request I am setting out below a summary of my principal conclusions.

The Annona Chalk Formation in Pine Island is an excellent candidate for the mining-drain hole project contemplated. The 75 acre Logan lease has an oil resource as follows

Original Oil in Place	141 thousand barrels per acre
Past Production	7 thousand barrels per acre
Present Oil in Place	134 thousand barrels per acre

The low past recovery (5%) is due to the limited effective drainage radius around a single conventional well – perhaps an acre or two. The formation porosity is excellent, however, the permeability is very low but uniform. Thus the large amount of oil in place but low past recovery.

The mining-drain hole project will provide 9 to perhaps 12 drain holes per ½ acre (one work room) providing some 1200 feet of pay exposure per ½ acre. This is compared to 120 feet for a single conventional well. The planned recovery sequence is (1) Pressure depletion, (2) Steam and or gas injection, (3) Gravity drainage. Gravity may assist all along but it will prevail during the final stripping down phase.

A typical work room with 9 drain holes is estimated to have a producing rate as follows with the pressure depletion drive.

	Bbls per day	*Cumulative Production*		*Recovery Efficiency*
		1,000 bbls	*Percent*	*Percent*
Initial	97 0		—	
100 days	50 0	7 2	35	
500 days	7 7	15 6	76	22 9
1000 days	2 9	17 8	86	26 2
1800 days	2 3	19 7	96	29 0
2200 days	2 3	20 6	100	30 3

It is expected that groups of wells will be drilled then put on production simultaneously. Maybe one or two work rooms at a time. New wells coming on will offset declines of earlier completed wells.

When oil production at a work room declines to perhaps 1 to 1½ barrels per drainhole (9 - 13 bbls per workroom) steam and or gas (perhaps nitrogen) injection can be initiated at perhaps 3 or 4 of the 9 to 12 wells in a work room. This will augment the natural production rate. Production from a workroom may build back up to 15 to 20 bbls per day from a typical work room declining towards 5 over the next 6 - 8 years.

Recovery per acre by normal depletion from the mining project is estimated to be about 40,000 bbls or 30% of the present oil in place after six years production. Recovery may be significantly higher if steam and or gas injection can be engineered to fully sweep the formation. Recovery could approach 70 to 80 thousand barrels per acre over ten year project life.

Yours faithfully

Lloyd E. Elkins

EXHIBIT "C"

The Directors
Petroleum Mining Company Limited
37 Athol Street
Douglas
Isle of Man

3635 S Sheridan
Tulsa, Oklahoma 74145
USA

31st October 1983

Dear Sirs

Critique
Feasibility Report
Oil Mining
Pine Island Oil Field
Caddo Parish, Louisiana

Introduction

McCarthy Engineering & Construction, Inc. was authorized by Petroleum Mining Corporation to conduct a feasibility study to evaluate subsurface conditions at the Logan Lease. The study consisted of reviewing all available geological records and data on the history of oil mining, including studies recently made for the US Bureau of Mines and the Department of Energy. One core hole was drilled on the lease. Samples were tested and logged for laboratory analysis by Cities Service and the Colorado School of Mines. An engineering analysis was obtained from the field work. At the conclusion of the above, engineering drawings and a cost analysis were prepared.

McCarthy Oil Mining Drainage Technique

McCarthy's thirty years experience in underground mining, LPG storage and Atomic Energy Commission work has evolved to a unique approach to the mine assisted method of oil recovery by drainage.

The Department of Energy instituted studies on the feasibility of oil production by mining methods. These studies included everything from mining the host rock to remote drainage.

After exhaustive studies, the consensus was that remote drainage was the safest and most economical alternative for producing oil using mining techniques and that the Annona Chalk is an excellent site selection.

The mining formation immediately below the Annona Chalk is competent and ideal for the mining zone.

McCarthy has developed a quick, easy method of drilling and securing the conductor pipe into the roof section. The drainage drilling would be safe, economically expedient and that the drainage plan would be extensive and of great density.

The water-oil-gas outflow from the drill holes will be encased from the hole collar. The gas and oil-water mixture would be piped to the surface in separate pipes. Additional separation facilities and sumps will be located on surface to upgrade the product to pipeline quality.

Using the McCarthy method of drilled shafts penetrating the formation immediately below the oil producing formation and having a high density of drainage holes, a quick return on investment can be achieved.

Our economic analysis is predicated upon a 30% recovery, whereas the Government studies indicate a 50% recovery. With steam and/or gas injection, Lloyd E. Elkins estimates recovery could be as high as 60%.

The Annona Chalk conventional production wells have always averaged a barrel per day. Using drainage method, we should improve upon that rate. The two equations used in our analysis are the Muskat and the Hutchins.

Mining and Drilling

The large diameter drilled hole has found acceptance in the mining and oil projects for use as a mine shaft since 1957.

During the 1960's the Atomic Energy Commission was forced to perform all of their detonations underground. Holes up to twelve feet in diameter were drilled to six thousand feet. Many large mines use the drill hole for secondary escapeway and for ventilation.

A total of 67 LP Gas storage caverns have been mined through drilled shafts in the USA, at depths ranging from 200 to 1800 feet below surface. The normal size shaft for this work is 42 inch diameter.

Our 800HP hoist and headframe was developed for use in small diameter shafts. It is capable of hoisting 20,000 pounds from varying depths to 2,000 feet maximum.

McCarthy Engineering & Construction, Inc. has been involved in the engineering, design and construction of a number of LP Gas caverns, including one at Morris, Grundy County, Illinois, which lies at a depth of 1801 - 1850 feet below the surface.

The Caddo-Pine Island oil mine will be initially constructed in the Ozan Shale section directly beneath the Annona Chalk. The projected depth of the mine roof is 1620 feet below the surface.

EXHIBIT "D"

The shaft sizes will be tailored to meet the hoisting and ventilation requirements. Two 75HP fans will be located on surface and will deliver 30,000 cubic feet per minute of fresh air to the mine. Additional blowers will be used underground.

The mining consists of driving a small number of 10 by 10 foot openings. The drifts are widely spaced with drilling alcoves spaced at 50 foot intervals.

The drilling pattern is shaped like the spokes of a part-wheel, radiating upwards to penetrate the oil bearing horizon in the top section of the Annona Chalk. The holes will be at 50 foot centers at total depth.

A 6-inch by 10 foot long hole will be drilled, cemented and cased before the drainage hole is drilled. Prior to doing any drilling, hydrostatic pressure tests will be conducted on a number of test casings to insure that they will withstand anticipated gas pressures. The 4-inch casing is threaded on the exposed end for attaching a valve, a device called a stuffing box.

The drilling will be accomplished using a rotary drill which was designed for degasification in the underground coal mines. The long drill hole is designed to handle ten foot steel changes and to penetrate depths of 3000 feet. The drill has all the safety features necessary for working in gassy (Methane) conditions. Cuttings (drill water or air, oil and gas) will be manifolded and attached to a 4-inch main line installed in each heading to drain into a collector tank after removing the solids.

Conclusions

1. That the Annona chalk has approximately 90,000 to 120,000 bbls. of oil to the acre. That less than 5 per cent has been extracted by conventional oil field techniques. That oil production from the Annona chalk averages 0.75 to 1.75 bbls. per day per well.
2. That all the government studies indicate that mining oil is economical and that the drainage method is the safest and most viable method.
3. The government studies indicate that 50 per cent of the oil in place should drain.
4. That the laboratory tests indicate that the Logan Lease contains in excess of 100,800 bbls. to the acre of 43 gravity oil.
5. That the McCarthy oil mining drainage technique is a viable means of extracting oil from the Annona chalk formation.
6. That proven and tested technology is available to economically extract the oil from the Annona chalk by the McCarthy mining drainage system.
7. That the base of the Annona chalk and the Ozan shale is competent for mining and is relatively impervious.
8. That the rock extraction during the mining operation be kept at a minimum to optimise the cash flow.
9. That the main and the ventilation shafts be drilled and cased from surface to the proposed roof of the underground excavation.
10. That the oil obtained by the drainage system be maintained in a closed system and pumped to surface.

Recommendations

1. That the south sixty acres of the Logan Lease be used for the first mining drainage in the Annona chalk.
2. That the roof of the underground excavation be in the bottom two feet of the Annona chalk or an approximate depth of 1620 feet.
3. That none of the drainage holes penetrate within 50 feet of the property line.
4. That a 64 inch diameter drilled hole with a 48 inch diameter steel liner from surface to the roof of the mine be cemented in place and used for the main shaft.
5. That two 42 inch diameter drilled shafts with 36 inch liner be used for the ventilation shafts. That a minimum of 25,000 cfm of air be circulated for proper ventilation.
6. That an auxiliary diesel hoist capable of spooling 1800 feet of cable be at the site. That the ventilation shafts be equipped as a secondary means to the underground excavations.
7. That the mining openings be kept to a minimum X-section of 10 feet wide by 10 feet high.
8. That a test chamber be set up immediately underground to obtain insitu drainage characteristics.
9. That the mining be separated from the drainage drilling.
10. That a minimum of a 1,000 drainage holes be drilled penetrating all of the producing zones.

Yours faithfully

D. F. McCarthy
for McCarthy Engineering & Construction Inc

FEASIBILITY REPORT

OIL MINING

PINE ISLAND OIL FIELD
CADDO PARISH, LOUISIANA

PREPARED FOR

PETROLEUM MINING CORPORATION

NEW ORLEANS, LOUISIANA

BY

McCarthy Engineering & Construction, Inc.
Tulsa, Oklahoma
Revised May, 1982

EXHIBIT "E-1"

McCARTHY
ENGINEERING/CONSTRUCTION, INC.

May, 1982

Petroleum Mining Corp.
Suite 2440
601 Poydras Street
New Orleans, Louisiana 70130

Attention: Mr. Jeffrey A. Miller, Pres.

Gentlemen:

In accordance with the Contract dated April, 1981, between Petroleum Mining Corp. and McCarthy Engineering & Construction, Inc., the evaluation of the subsurface conditions relevant to the construction of the oil mining drainage operation at the Logan lease, Pine Island oil field, Caddo Parish, Louisiana, was completed in June, 1981.

The report submitted at that time reviewed the geology and historic and evolution of the drilling, enhancement and production of oil from the Annona chalk. All government reports pertaining to oil mining were reviewed.

This report includes every item included in the June, 1981, report with a revised construction cost and schedule and a revised cash flow reflecting the latest oil value.

During the last year there have been many meetings and our conclusion is that the oil mining of the Annona chalk in the Pine Island field is very feasible.

Sincerely,

D. F. McCarthy

DFM/ajg

Attachments

3635 S. SHERIDAN ■ TULSA, OKLAHOMA 74145 ■ 918/622-0646

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INTRODUCTION

McCarthy Engineering & Construction, Inc. was authorized by an agreement dated April, 1981, to execute a feasibility study to evaluate subsurface conditions at the Logan lease located in the Caddo-Pine Island oil field, Caddo Parish, Louisiana, for Petroleum Mining Corporation (General Location Map).

The study consisted of the following:

1. Review available geological records.

2. Core one hole on the lease. This work was done between May 5th and 11th, 1981, by C. L. Morris, Inc., Oil City, Louisiana.

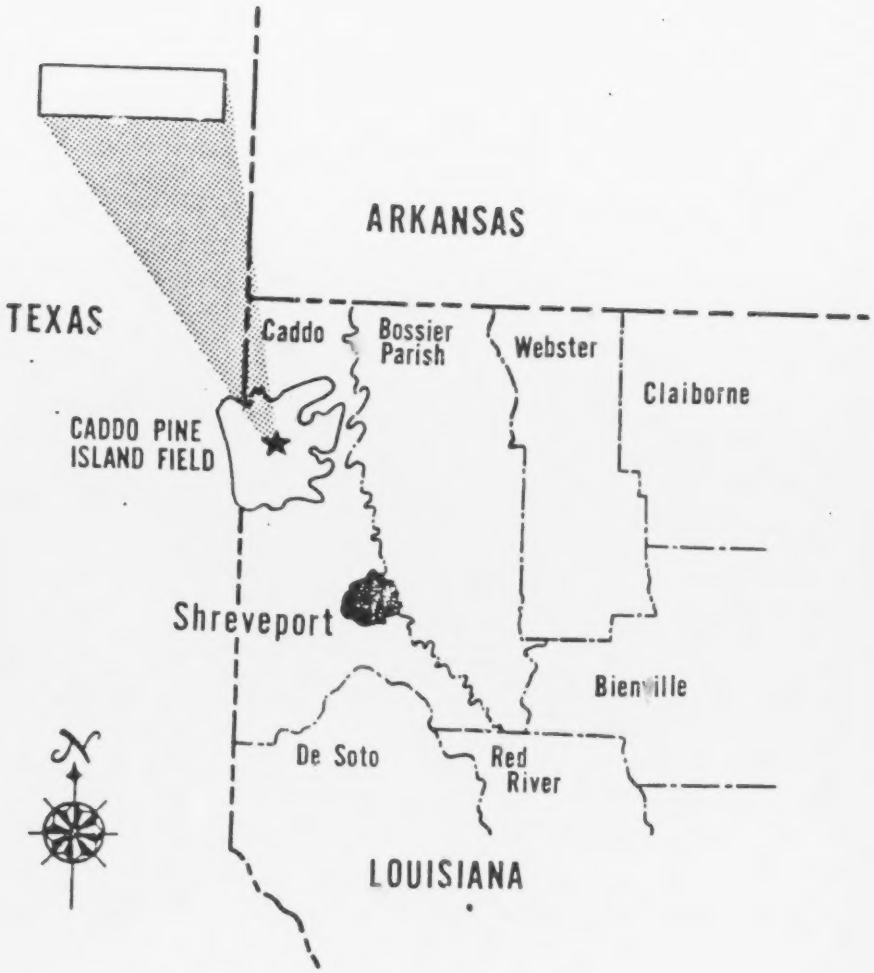
3. Logging and describing the cores and collecting samples for laboratory analysis.

4. Making an engineering analysis of the data obtained from the field work and laboratory analysis of the cores.

5. Review all available data on the history of oil mining including studies recently made for the U.S. Bureau of Mines and the Department of Energy.

6. Review and prepare cost analysis.

The report includes the information gathered during the course of the study, as well as recommendations and conclusions concerning the feasibility of construction a "in situ" oil mine.



General Location Map

CADDO PINE ISLAND

CADDO PARISH, LOUISIANA

McCARTHY OIL MINING
DRAINAGE TECHNIQUE

McCarthy's thirty years experience in underground mining, LPG storage and AEC work has evolved to a unique approach to the mine-assisted method of oil recovery by drainage.

The Department of Energy in the years 1978 to 1981 instituted several studies on the feasibility of oil production by mining methods. In these reports all types of mining techniques were analysized. These included direct stoping, block caving, shatter and drain, strip mining, terrace pit and of course, underground drainage.

"Drainage Methods

This group of methods is the furthest removed from a conventional mining approach but also, possibly, is the most promising of the underground options considered. All are variation of the same basic concept, which is that a network of underground tunnels is developed either in or adjacent to the oil-bearing zone. This tunnel system would provide the locations for drilling holes into the oil zone for production purposes and for stimulation if necessary. The availability of such holes at a greatly higher density than would be economically possible from surface has the potential to produce substantially enhanced recovery in fields of many types."

"Remote Drainage

The presence of a suitably competent, impermeable formation adjacent to the oil zone is the dominant criterion for this method. It could be either

above or below but does not need to be both." (1)

We contend that the mining interval should be immediately below the formation to minimize the pumping cost and maximize the oil flow.

McCarthy has developed a quick easy method of drilling and securing the conductor pipe into the immediate roof section of the mine for the start of the drainage holes. It is essential that the mining be kept to a minimum, the drainage drilling be safe, economically expedient and that the drainage plan be extensive and be of great density.

"The water-oil-gas outflow from the drill holes will be encased from the hole collar and flow or be pumped to a central sump near the shaft in gathering lines. Differential settling of sludge, solids, water and gases would take place to some extent in this sump. Taps at several elevations would permit a semi-separation at this point. The gas and oil-water mixture would be piped to the surface in separate pipes located for safety in a borehole rather than in either of the shafts. Additional separation facilities and sumps will be located on surface to upgrade the product to pipeline quality."

In our method none of the shafts will be used for removing the hydrocarbons.

Using the McCarthy method of drilled shafts penetrating the formation immediately below the oil producing formation and have a high density of drainage holes, a quick return on investment can be achieved.

In our economic analysis, we have used two different equations and have used 30% and 50% recovery. The 30% recovery is our conservative estimate; whereas the 50% recovery is based upon the government studies. For this operation to break even, we would need a recovery of 5-8 percent, or 0.15 Bbls. per day per drainage hole.

(1)Golder Associates, Inc.; Oil Mining, A Technical and Economic Feasibility Study of Oil Production by Mining Methods, NTIS Report No. PB-297-134, October 1978.

The Annona Chalk conventional production wells have always averaged a barrel per day. Using drainage method, we should improve upon that rate.

The two equations used in our analysis are the Muskat and the Hutchins.

"The Muskat's gravity drainage equation is expressed as

$$Q_r = 1.539 \times 10^{-3} \left(\frac{K_o}{B_o \mu_o} \right) \left(\frac{\delta_o h_2 (y^2 - x^2)}{\ln \left(\frac{re}{r_w} \right)} \right)$$

The equation in Hutchins' report is as follows:" (2)

$$Q_r = 3.0656 \times 15^{-3} \left(\frac{K_o}{B_o \mu_o} \right) \left(\frac{\delta_o h_o 2 (y^2 - x^2)}{\ln \left(\frac{0.472\ re}{r_w} \right)} \right)$$

where Q_r = production rate, STR/D/well

K_o = permeability to oil md

B_o = Oil formation volume factor, RBBL/STB

μ_o = oil viscosity, cp

δ_o = oil density, g/cc (sp. gr.)

h_o = reservoir thickness, ft

y = fraction of h_o at r_w

x = fraction of h_o at r_e

r_w = wellbore radium, ft

r_e = drainage radium, ft

Production rates are calculated using the Muskat's gravity drainage equation and are tabulated in Table 1 and Table 2 using the 30 and 50 percent recovery.

The production rate estimated by Hutchins' study is approximately twice the rate as calculated by Muskat equation.

(2) Colorado School of Mines; Cost Analysis of Recovery Light Oil by Gravity Drainage, January, 1981.

MINING & DRILLING

The large diameter drilled hole has found acceptance in the mining and civil projects for use as a mine shaft since 1957.

The State-of-the-Art increased tremendously during the 1960's when the Atomic Energy Commission was forced to perform all of their detonations underground. The large diameter holes were ideally suited for this operation. Holes up to twelve feet in diameter were drilled to six thousand feet. Many large mines use the drill hole for secondary escapeway and for ventilation.

A total of 67 LP Gas storage caverns have been mined through drilled shafts in the U.S.A., at depths ranging from 200 to 1800 feet below the surface.

Lake Shore, Inc., Iron Mountain, Michigan, developed a hoist and headframe combination for use in small diameter shafts that has been the most widely used. The combination is capable of hoisting 20,000 pounds from varying depths to 2,000 feet maximum. The conveyances, called skips, run on rope guides equipped with safety latches that activate if and when the hoist rope slackens. In an event where a hoist rope breaks, the safety dogs engage the guide ropes, and prevent the conveyance from falling through the shaft. A Ward-Leonard electrical control system is used with these hoists. We will use a Lake Shore 800 HP hoist and conveyance system on this project.

Over 4,200,000 (20 million barrels) cubic yards of material has been removed from the ground for LP Gas storage purposes. Almost all of the caverns have been mined in a room-and-pillar configuration, so designated because the

square unmined blocks of rock. The room-and-pillar method was developed in the coal fields in the late 1800's to support the mined-out areas, and prevent surface subsidence in the event of a cave-in. It is utilized in storage caverns not only for its structural soundness, but also because the required storage volume can be enclosed within a minimum area.

McCarthy Engineering and Construction, Inc., has been involved in the engineering, design and construction of a number of LP Gas caverns, including one at Morris, Grundy County, Illinois, which lies at a depth of 1801-1850 feet below the surface.

The Caddo-Pine Island oil mine will be initially constructed in the Ozan Shale section directly beneath the Annona Chalk. The projected depth of the roof of the mine is 1620 feet below the surface.

The shaft sizes have been tailored to meet the hoisting and ventilation requirements. The main shaft is 48-inches in diameter; two 36-inch ventilation shafts will provide sufficient air throughout the mining and oil drilling operations; and, a 14-inch utility shaft will provide access for compressed air, electrical cables, and possibly a diesel fuel line.

The mining consists of driving a small number of 10 X 10 foot openings. The drifts are widely spaced, and have been located to allow for drilling the oil drainage holes on a regular pattern to allow drainage from the 60 acre tract. The drifts along with their drilling alcoves, spaced at 50-foot intervals, total 7,500 feet in length. Only 3% of the rock in the 60 acre tract will be removed during the mining operation.

Ventilating air will be directed through the 36 inch I.D. drilled shafts and will be coursed to the working faces through 36-inch ventilating duct. Two 75 HP fans will be located on surface and will deliver 30,000 cubic feet

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per minute of fresh air to the mine. Additional blowers will be used underground to keep fresh air at the face.

Mining will be by conventional methods. The faces will be advanced by drilling and blasting. The broken rock will be hauled from the face to the shaft bottom in Eimco LHD (load haul dump) mucking machines, loaded into the skip and hoisted to the surface for disposal Using the chalk for the roof of the mine will ensure a strong durable back.

The drilling pattern is shaped like the spokes of a part-wheel, radiating upward to penetrate the oil bearing horizon in the top section of the Annona Chalk. About 1,000 holes will be required to drain the 60 acres. A brief description of the drilling operation follows:

A 6-inch by 10-foot long hole will be drilled, and cased with a 4-inch I.D. steel casing cemented in place. Prior to doing any drilling, hydrostatic pressure tests will be conducted on a number of test casings to insure that they will withstand anticipated gas pressures of 200 psig. The 4-inch casing is threaded on the exposed end for attaching a valve, and a device called a stuffing box. The stuffing box is the miner's equivalent of a blow out preventer.

The first section of drill steel with the three inch diameter bit attached in place through the stuffing box, and this assembly is attached to the cased hole. The drilling will be accomplished using a rotary drill designed by Fletcher Manufacturing and Consolidated Coal. This drill was designed for degasification in the underground coal mines. The long hole drill is designed to handle ten foot steel changes and to penetrate depths of 3000 feet. The drill has all the safety features necessary for working in gassey (Methane) conditions. It will drill a three inch hole in the chalk at the rate of

1.5 feet per minute. Cuttings, drill water or air, oil and gas are removed from the hole through a pipeline attached to the return side of the stuffing box. The 2-inch return lines from the stuffing boxes will be manifolded and attached to a 4 inch main line installed in each heading to drain the oil and gas into a collector tank after removing the solids at a location remote from the drilling alcove.

GEOLOGICAL & HISTORIC

BACKGROUND OF THE CADDO-PINE ISLAND FIELD*

The Caddo-Pine Island field is located approximately 15 miles north of the City of Shreveport in Caddo Parish, Louisiana, and Marion County, Texas. This discourse will be confined to remarks related to the Annona Chalk reservoir situated in the north-central part of the field in Caddo Parish.

"The production from the Chalk is associated with faulting and natural fracturing of the formation and is found in several fields in North Louisiana. The discovery well in the Caddo-Pine Island field was the Savage Bros. & Morrical No. 1 Offenhauser, which was completed March 28, 1905, in the Annona Chalk at a depth of 1,556 feet. The well was located near Oil City, Louisiana, and had an initial production of 5 barrels per day of 34° gravity oil. This well was considered non-commercial by the operators and was soon plugged and abandoned. However, this discovery led to further development. By the close of 1907, twenty-three wells had been drilled--eight of which produced oil, 11 produced gas, and four were abandoned. Development of the field contunued at a rapid pace during the following years, and by 1918 the production reached a peak of 11 million bbl./yr.

"The Caddo-Pine Island producing area is associated with a dome relating to and on the northern flank of the Sabine Uplift. The structure is a graben type completely faulted dome with over 2,500 feet of closure on the Ferry Lake Anhydrite. The primary uplift occurred at the close of the Lower Cretaceous

*The information contained in this section has been copied from articles as noted.

period, was then followed by erosion and later by the encroachment of the Upper Cretaceous seas.

"The initial sedimet of the Upper Cretaceous was the Eagleford shale and was followed by the deposition of the Tokio, Ozan, Annona, Marlbrook, Saratoga, Nocatock, Arkadelphia, Midway and Wilcox formations. The Midway and Wilcox are Eocene in age. Subsequent to the deposition of the Upper Cretaceous beds, the dome experienced additional uplife and the crest of the dome on the Annona Chalk was shifted to the southwest in the vicinity of Oil City, Louisiana.

"The major accumulation of oil in the Chalk is found on the south up-thrown side of the Oil City fault. Also, there are numerous en-echelon, down to the north, epidomal, normal faults which locally control the more prolific accumulations of oil in the Annona Chalk. The Chalk is productive between a subsea depth of 1,300 to 1,470 feet. In the main producing area, however a large portion of the southern flank of the dome is unproductive although the Chalk is found above a subsea depth of 1,470 feet.

"Although there have been a considerable number of wells drilled in the field, only a limited amount of core data have been obtained and the formation characteristics listed below have been shown to cover the average condition that exists in the Annona Chalk.

Average permeability: Less than 0.1 to 1.5 md
Average porosity: 25 to 28 per cent
Residual Oil saturation: 15 to 35% of pore space
Total water saturation: 30 to 60% of pore space but can be as high as 75% and still produce oil.
Average pore volume: 1,500 to 2,000 bbl./acre ft.
Estimated recovery: 10 to 20% of oil in place
Gas/oil ratio: 1,000 to 1,500 cu.ft./bbl.
Gravity of oils: 34 to 40° API
Average thickness: 185 ft. Average thickness of producing section 140 to 160 feet.
Type drive: Gravity drainage
Drainage area: 1 to 2 1/2 acres.

"The subsurface pressure data are also very limited in the field, but during the first six months of 1955 pressure tests were made on six wells prior to fracturing and seven wells after fracturing. The wells were selected to give a wide spread in the Chalk producing area the the pressures prior to fracturing from 300 to 400 psig with limited shut-in periods from five to 12 hours. The original bottom hole pressure has been estimated at 750 psig"(1)

No rock temperatures were recorded in the literature reviewed. A simgle temperature of 97° F was recorded in the Ozan shale at a depth of 1740 feet on May 12, 1981, on the Logan lease. This correlates fairly close to the regional isotherms of 2°-2.1° per 100 feet and an average ambient of 66° F. At Cargill salt mine 300 miles to the south at the same depth of 1600 feet the rock temperature in the mine is at 88° F.

"The Annona Chalk reservoir is not producible under natural drive, but is producible by the use of various stimulation techniques. With the advent of each new engineering advance for the stimulation of production in tight formations, this field has gone through a boom. Each of the new methods has increased production for a short time followed by a long period of production at rates of two barrels per day per well or less. All methods used have been economically feasible.

"A geological report made in 1958 by Arkansas Fuel Oil geologists gives a brief history of the field. It shows that the first wells were completed open hole from top to bottom in the Chalk. A charge of nitroglycerine was placed in the well and exploded. The production from these wells was high initially, rapidly declining to one to two barrels per day.

(1)Patterson, B.F., Hydraulic Fracturing in the Caddo-Pine Island Field, Journal of Petroleum Technology, November 15, 1956.

"The introduction of acid into the petroleum business started another phase of activity. The wells were completed exactly as in the first boom, open hole from top to bottom. The entire section was acidized and again high initial rates were obtained, and again the rapid decline to stabilization.

"The second stage of the acid phase arrived when it was discovered that the acid was spent before it reached the bottom of the hole. The bottom zone of the Chalk is the hardest section, and therefore most in need of stimulation. When this was realized, another boom began. This time the casing string was set through the top of the Chalk and the bottom zone acidized. This again gave the high rates, rapid decline, and stabilization.

"A later technique used in the field was fracturing. This method used hydraulic pressure to separate the formation, and sand carried in oil as a means of propping open the fractures thus created. Again as in the past there was the initial increase in production this time to a greater degree than before, but with the same rapid decline after treatment.

"The two most recent techniques involve two different philosophies. Texaco has initiated a five-pattern program of inhibition flooding. This is a long-term prospect since no effort is made to inject the water under pressure. The chalk is allowed to soak up the water as slow or as fast as it can. The results of this approach probably won't be known for sometime to come.

"Talley-Frac, Inc. has taken over a 40-well lease and tried their technique on four wells. This approach involves pumping an explosive slurry into the formation and detonating it. The effective well bore is thus greatly increased and, hopefully, so is production. The drawbacks to this method at the present time are the damage that the producing well as a result of the explosion and the workover problems encountered in trying to clean out the

rubblized wellbore."(2)

According to Mr. W.S. Snowden, over 14,000 wells have been drilled into the Annona Chalk reservoir to date (Personal Communication). The Annona Chalk oil is a sweet paraffin-based crude, and is considered to be premium quality oil. The records indicate that only a small percentage (less than 2 to 8%) of the original deposits have been recovered from the field. Petroleum Mining Corp. envisions a new approach towards producing a large percentage of the remaining reserves by mining access rooms in the underlying formation, and drilling small diameter, closely spaced holes into the overlying Annona Chalk reservoir.

(2)Brown, L.P., Presentation of an Explosive Stimulation Project in the Annona Chalk, Caddo-Pine Island field, Caddo Parish, Louisiana, Cities Service Oil Co. August, 1971.

CONCLUSIONS

1. That the Annona chalk has approximately 90,000 to 120,000 bbls. of oil to the acre. That less than 5 per cent has been extracted by conventional oil field techniques. That oil production from the Annona chalk average 0.75 to 1.75 bbls. per day per well.

2. That all the government studies indicate that mining oil is economical and that the drainage method is the safest and most viable method.

3. The government studies indicate that 50 per cent of the oil in place should drain.

4. That the laboratory test indicate that the Logan lease contains in excess of 100,800 bbls. to the acre of 43 gravity oil.

5. That the McCarthy oil mining drainage technique is a viable means of extracting oil from the Annona chalk formation.

6. That proven and tested technology is available to economically extract the oil from the Annona chalk by the McCarthy mining drainage system.

7. That the base of the Annona chalk and the Ozan shale is competent for mining and is relatively impervious.

8. That the rock extraction during the mining operation be kept at a minimum to optimise the cash flow.

9. That the main and the ventilation shafts be drilled and cased from surface to the proposed roof of the underground excavation.

10. That the oil obtained by the drainage system be maintained in a closed system and pumped to surface.

RECOMMENDATIONS

1. That the south sixty acres of the Logan lease be used for the first mining drainage in the Annona chalk.

2. That the roof of the underground excavation be in the bottom two feet of the Annona chalk or an approximate depth of 1620 feet.

3. That none of the drainage holes penetrate within 50 feet of the property line.

4. That a 64 inch diameter drilled hole with a 48 inch diameter steel liner from surface to the roof of the mine be cemented in place and used for the main shaft.

5. That two 42-inch diameter drilled shafts with 36-inch liner be used for the ventilation shafts. That a minimum of 25,000 cfm of air be circulated for proper ventilation.

6. That an auxiliary diesel hoist capable of spooling 1800 feet of cable be at the site. That the ventilation shafts be equipped as a secondary means to the underground excavations.

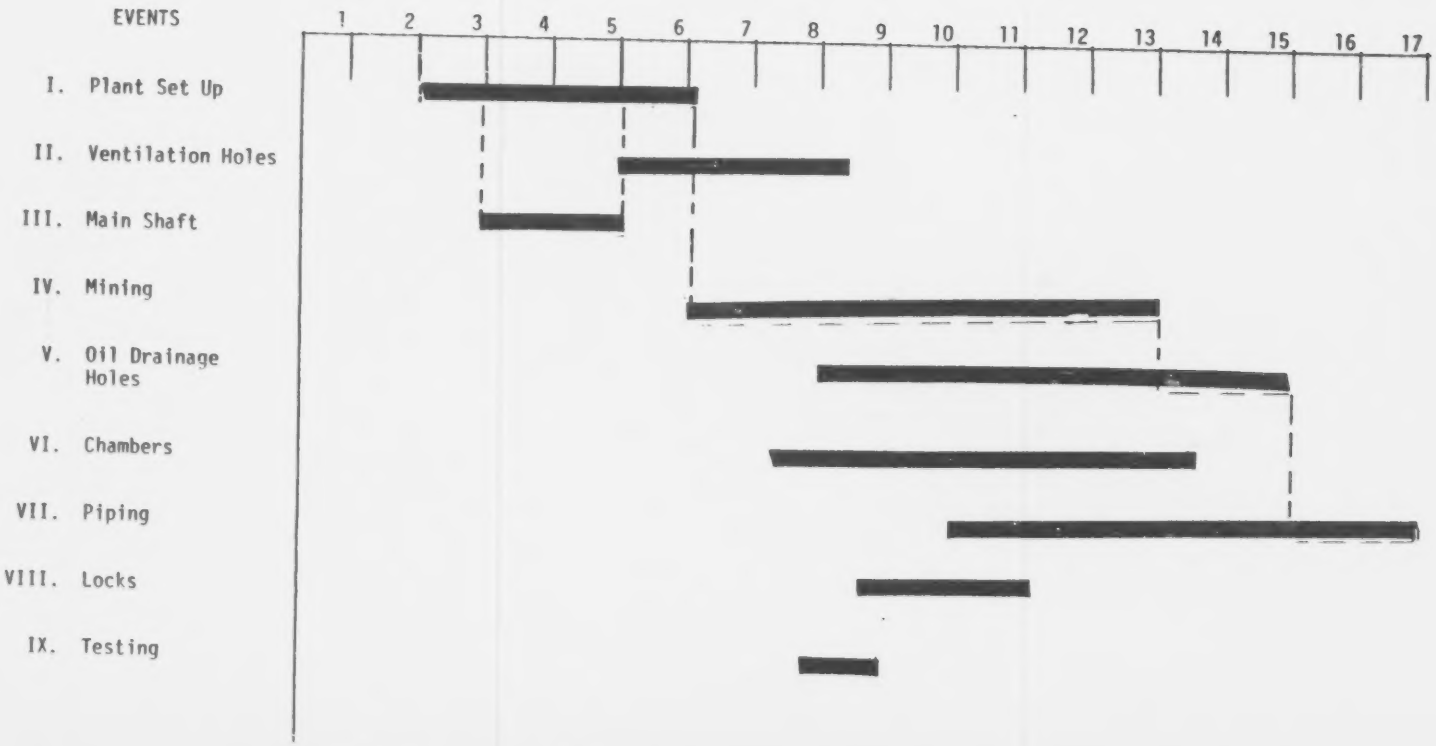
7. That the mining openings be kept to a minimum X-section of 10 feet wide by 10 feet high.

8. That a test chamber be set up immediately underground to obtain insitu drainage characteristics.

9. That the mining be separated from the drainage drilling.

10. That a minimum of a 1,000 drainage holes be drilled penetrating all of producing zones.

60 ACRE
LOGAN LEASE
CONSTRUCTION SCHEDULE
TIME (MONTHS)
Revised May, 1982



---------- Critical Path

COST BREAKDOWN
LOGAN LEASE
60 ACRES
May, 1982 (Revised)

ITEM	DESCRIPTION	LABOR	BURDEN	MATERIAL*	TOTAL
I	Plant Set Up	$ 15,840.	$ 4,910.	$ 229,020.	$ 249,770.
II	Ventilation Holes	50,400.	15,624.	1,668,804.	1,734,828.
III	Main Shaft	40,800.	12,648.	1,104,708.	1,158,156.
IV	Mining	1,700,000	527,118.	2,510,900.	4,738,018.
V	Oil Drainage Holes	525,000.	162,200.	790,600.	1,477,800.
VI	Chambers	190,000.	58,800.	454,800.	703,600.
VII	Piping	80,500.	24,956.	129,800.	235,256.
VIII	Locks	40,800.	12,648.	72,000.	125,448.
IX	Testing	28,800.	8,928.	39,996.	77,724.
		$2,672,140	$827,832.	$7,000,628.	$10,500,600.

*Material includes equipment, small holes, sub contractors & materials

LABORATORY TESTS

Representative samples were selected and prepared from the core recovery from the Logan number 1 hole and the following tests were performed by Cities Service at their research laboratory in Tulsa, Oklahoma.

(a). permeability to air

(b). porosity

(c). grain density

(d). bulk density

(e). fluid saturation to oil and water

(f). unconfined compressive strength

(g). Poisson's ratio

(h). Young's modulus

(i). Chemical composition

(j). Water jet perforation

(k). Seven day water immersion

The seven day water immersion test was conducted by McCarthy Engineering and Construction, Inc. and the water jet cutting tests were conducted by the Colorado School of Mines.

For the first five tests outlined, samples were taken every ten feet from the top of the chalk down through the shale zone; whereas the other tests were conducted on the samples that pertained to the mine opening.

CORE SUMMARY AND CALCULATED RECOVERABLE OIL

FORMATION NAME AND DEPTH INTERVAL: Annona Chalk 1435-1495		
Feet of core recovered from above interval	56	
Feet of core included in averages	60	
Average Permeability: Millidarcys	.30	
Productive Capacity: Millidarcy-Feet	.18	
Average Porosity: Per Cent	21.26	
Average Residual Oil Saturation: Per Cent of Pore Space	29.5	
Average Total Water Saturation: Per Cent of Pore Space	12.8	
Calculated Original Stock-Tank Oil in Place Barrels Per Acre-Foot	1049	
Barrels per Acre		62,975

FORMATION NAME AND DEPTH INTERVAL: Annona Chalk 1505-1545		
Feet of core recovered from above interval	40	
Feet of core included in averages	40	
Average Permeability: Millidarcys	.25	
Productive Capacity: Millidarcy-Feet	10	
Average Porosity: Per Cent	18.64	
Average Residual Oil Saturation: Per Cent of Pore Space	14.2	
Average Total Water Saturation: Per Cent of Pore Space	23.46	
Calculated Original Stock-Tank Oil in Place: Barrels per Acre-Foot	499.6	
Barrels per Acre		19,982

CORE SUMMARY AND CALCULATED RECOVERABLE OIL

FORMATION NAME AND DEPTH INTERVAL:	Annona Chalk 1545-1578	
Feet of core recovered from above interval	33	
Feet of core included in averages	33	
Average Permeability: Millidarcys	1.25	
Productive Capacity: Millidarcy-Feet	41	
Average Porosity: Per Cent	20.28	
Average Residual Oil Saturation: Per Cent of Pore Space	15.3	
Average Total Water Saturation: Per Cent of Pore Space	25.28	
Calculated Original Stock-Tank Oil in Place Barrels Per Acre-Foot	540.6	
Barrels per Acre		17,841

FORMATION NAME AND DEPTH INTERVAL:		
Feet of core recovered from above interval		
Feet of core included in averages		
Average Permeability: Millidarcys		
Productive Capacity: Millidarcy-Feet		
Average Porosity: Per Cent		
Average Residual Oil Saturation: Per Cent of Pore Space		
Average Total Water Saturation: Per Cent of Pore Space		
Calculated Original Stock-Tank Oil in Place: Barrels per Acre-Foot		
Barrels per Acre (TOTAL - Page 1 & 2)		100,798

RQD
(Rock Quality Designation)*

DEPTH (Ft.)	FEET DRILLED	RECOVERY (ft.)	RECOVERY (%)	SAMPLES Less than 4" (Ins.)	CLASSIFICATION
1370-1417	47	47	100	12	Excellent
1417-1461	44	41	93	4.25	Excellent
1461-1498	37	33	89	36	Good
1498-1547	49	48.9	99	30	Excellent
1547-1595	48	48	100	3	Excellent
1595-1640	45	44.5	99	33	Excellent
1640-1690	50	49.8	99	43	Excellent
1690-1740	50	50.75	100	68.75	Good

* RQD is a method developed by Dr. Deere in 1964, which provides a preliminary estimate of the variation of the rock in place rock mass properties of the "sound" portion of the rock core.

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****
****
SUMMARY OF SEMI-QUANTITATIVE ANALYSES
****
****

XRD SAMPLE HEADER: BULK LOGAN #1, CADDO PARISH, LA. * Before Acidizing

****** COMPOSITION (PERCENT) *****

DEPTH	ILLITE	QUARTZ	KAOLIN	MICROC	CALCIT	DOLOMI
1623.5	3.1	31.1	2.4	1.7	51.9	9.8

****
****
SUMMARY OF SEMI-QUANTITATIVE ANALYSES
****
****

XRD SAMPLE HEADER: BULK LOGAN #1, CADDO PARISH, LA. *Before Acidizing

***** COMPOSITION (PERCENT) *****

DEPTH	PYRITE	ILLITE	QUARTZ	KAOLIN	CALCIT	DOLOMI
1618	.0	.0	11.5	.0	79.5	9.0
1627	.6	4.4	60.4	5.0	20.9	8.7
1628	.8	2.8	71.4	3.0	17.3	3.4
1633	.7	.0	53.8	4.2	37.6	3.6
1660	.5	4.1	48.2	3.4	32.8	11.0

McCARTHY'S COMMENTS:

The Magnitude of swelling from absorption of water by clays depends upon the kind and amounts of clay minerals present, their exchangable ions, electrolyte content of the aqueous phase, particle size distribution, void size and distribution, the internal structure, water content, superimposed loads, and possibly other factors. Only the illite and kaolinite (approximately 10% of the bulk composition) have any magnitude of swelling and this is the range of 10-30%. The results of the seven day immersion test validate these findings.

****
****
SUMMARY OF SEMI-QUANTITATIVE ANLAYSES
****
****

XRD SAMPLE HEADER: BULK LOGAN #1, CADDO PARISH, LA.

***** COMPOSITION (PERCENT) *****

DEPTH	PYRITE	ILLITE	QUARTZ	KAOLIN	MICROC	CALCIT	DOLOMI
1625	.6	4.8	46.1	4.6	2.1	26.5	15.2

****
****
SUMMARY OF SEMI-QUANTITATIVE ANALYSES
****
****

XRD SAMPLE HEADER: 5 MICRON INSOLUBLE RESIDUE LOGAN #1, CADDO PARISH, LA.

***** COMPOSITION (PERCENT) ******

DEPTH	PYRITE	CHLORI	ILLITE	QUARTZ	KAOLIN	MICROC	PLAGIO
1618	.8	2.2	14.4	30.8	48.4	3.4	.0
1623.5	.3	1.9	18.3	10.7	64.9	4.0	.0
1625	.0	2.2	22.3	3.9	67.2	4.5	.0
1627	.0	2.0	16.6	10.0	66.1	3.2	2.1
1628	.0	3.1	22.8	6.3	64.7	3.1	.0
1633	.6	1.4	17.5	30.7	46.4	3.4	.0

****
****
SUMMARY OF SEMI-QUANTITATIVE ANALYSES
****
****

XRD SAMPLE HEADER: BULK-INSOLUBLE RESIDUE-LOGAN #1, CADDO PARISH, LA.

****** COMPOSITION (PERCENT) ******

DEPTH	PYRITE	CHLORI	ILLITE	QUARTZ	KAOLIN	MICROC	PLAGIO
1618	1.2	.0	.0	85.6	10.5	2.7	.0
1623.5	.6	.0	4.7	83.3	6.1	5.3	.0
1625	.6	.0	4.2	87.0	5.2	.0	3.0
1627	.7	1.4	4.8	84.8	6.0	1.3	1.0
1628	1.1	.0	6.3	83.6	9.0	.0	.0
1633	1.0	.0	5.3	84.5	7.2	2.0	.0

UNCONFINED COMPRESSIVE STRENGTH

Sample No.	Depth (Ft.)	Description	L/D	Compressive Strength (PSI)
1	1618	Chalk	2.64	4575
2	1627	Shale	1.80	4169
3	1633	Shale	1.93	4250
4	1625	Shale w/ chalk	1.97	4050
5*	1623.5	Chalk w/ shale	2.01	4968

* Youngs Modulus 1.37×10^6 psi
Poisson's Ratio 0.23

SEVEN DAY WATER IMMERSION

Two samples were subjected to alternating 24 hour immersion into tap water at room temperature and then 24 hours at atmospheric conditions.

Sample #1
Six inch chalk sample from a depth of 1620 feet.

Sample #2
Six inch shale sample from a depth of 1635 feet.

Sample	Date	Immersion Water	Immersion Air	Observation
Shale	May 18	X		Very little change, some silt observed in water.
Chale	May 18	X		Very little change, some fine particles in water
Shale	May 19		X	Shale had small pieces break off
Chalk	May 19		X	No change
Shale	May 20	X		Shale showing large cracks
Chalk	May 20	X		No change
Shale	May 21		X	Shale breaking up
Chalk	May 21		X	No change
Shale	May 22	X		Shale continues to fall or part
Chalk	May 22	X		No change
Shale	May 23		X	Shale largest piece measured 1.3" thickest location
Chalk	May 23		X	No change
Shale	May 24	X		Largest piece showing cracks and will probably all break apart whil in water the next 24 hours.
Chalk	May 24	X		No change
Shale	May 25		X	Largest piece broke in half and showed cracks throughout
Chalk	May 25		X	No change. 1/16" piece of shale fell off.

LAB REPORT #060181.B1

Water Jet Kerfing of Chalk

The chalk tested was shown to be quite amenable to water jet cutting even at a relatively low pressure range of 5,000 to 10,000 psi. The rock possesses numerious fractures which, for many excavation purposes, suggests that water jet cutting would produce an excellent means of fragmentation, particularly in the low pressure, high flow rate range.

Tests were conducted utilizing two jet pressures (5,000 and 10,000 psi), five traverse velocities (2.5, 5, 10,35 & 50 inches per second) and three orifice diameters (.016, .020 and .035 inches). Successful cutting was possible with all combinations of perameters. In the case of .035 inch diameter jet a pressure of 10,000 psi caused the entire sample to shatter due to the existing fractures being filled and pressurized. Although the sample was unconfined the existing fractures coupled with a very high amenability for pure jet errosion demonstrates a very positive potential for the application of water jets in drilling this rock type.

N. J. Bonge

Research Associate
Colorado School of Mines

Lab Report #060181.B1

Test Results

Test No	Orifice Dia (inches)	Pressure (psi)	Flow Rate (gpm)	Power (HHP)	Traverse Velocity (in/sec)	No. of Passes	Average Kerf Depth (in)
1	.016	5,000	.42	1.2	2.5	1	.033
2	.016	10,000	.59	3.5	2.5	1	.081
3	.016	5,000	.42	1.2	5	1	.021
4	.016	10,000	.59	3.5	5	1	.058
5	.016	5,000	.42	1.2	10	1	.010
6	.016	10,000	.59	3.5	10	1	.042
7	.016	5,000	.42	1.2	35	1	.004
8	.016	10,000	.59	3.5	35	1	.009
9	.016	5,000	.42	1.2	50	1	.002
10	.016	10,000	.59	3.5	50	1	.012
11	.016	10,000	.59	3.5	5	10	.142
12	.020	5,000	.66	1.9	2.5	1	.041
13	.020	10,000	.93	5.4	2.5	1	.134
14	.020	5,000	.66	1.9	5	1	.036
15	.020	10,000	.93	5.4	5	1	.096
16	.020	5,000	.66	1.9	10	1	.024
17	.020	10,000	.93	5.4	10	1	.040
18	.020	5,000	.66	1.9	35	1	.005
19	.020	10,000	.93	5.4	35	1	.025
20	.020	5,000	.66	1.9	50	1	.0015
21	.020	10,000	.93	5.4	50	1	.008
22	.035	5,000	2.0	5.9	2.5	1	.078
23	.035	10,000	2.8	16.6	2.5	1	≈.540

Sample 1-11 @ depth of 1422.5'; Sample 12-21 @ depth of 1474'; Sample 22-23 @ depth of 1564'

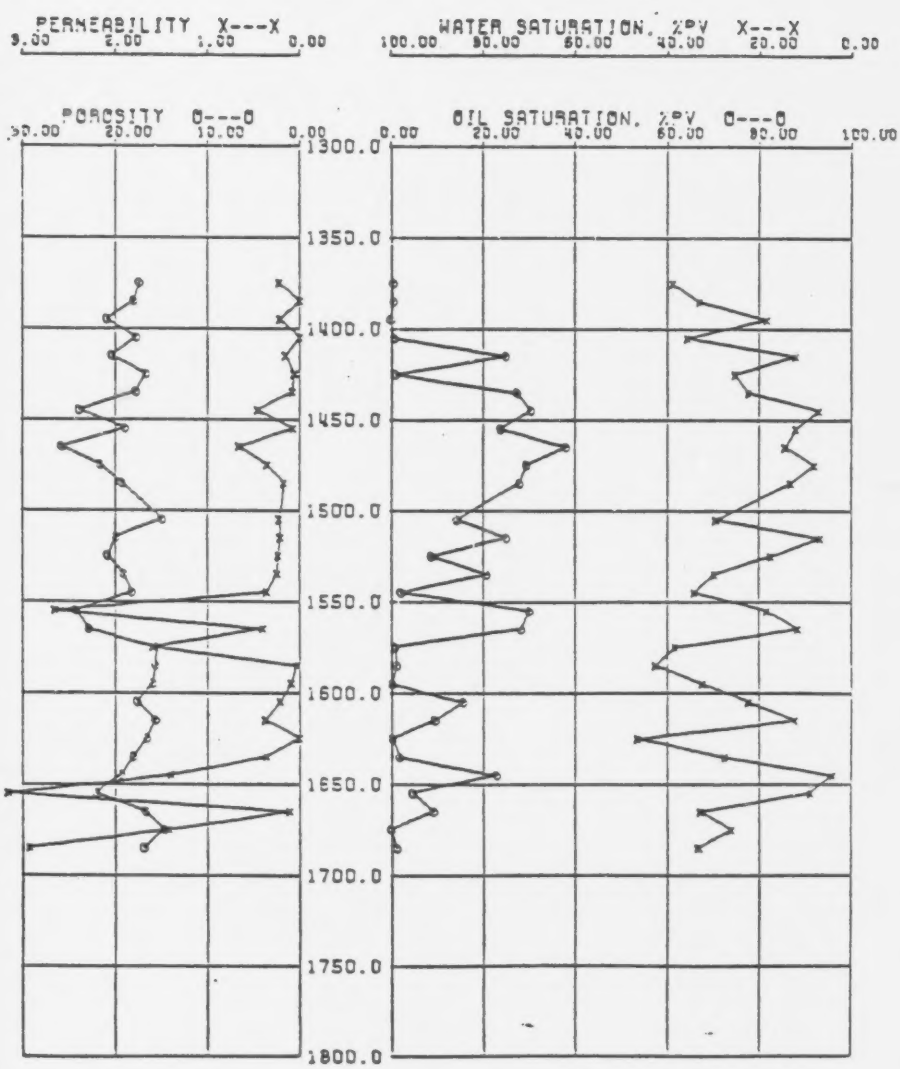
WELL NAME: LOGAN #1
FORMATION: ANNONA CHALK
DATE RECEIVED:
CORING FLUID: WATER
DATE ANALYZED: 6/20/81

FIELD NAME:
LOCATION: CADDO PARRISH
LOUISIANA
ELEVATION:

DEPTH (FT)	PERMEABILITY TO AIR, MD	POROSITY PCI	GRAIN DENSITY	BULK DENSITY	FLUID SATS. OIL	WTR	COMMENTS
1375.0	.220	17.42	2.71	2.24	.5	38.9	
1385.0	BROKEN	18.03	2.71	2.22	.6	32.9	
1395.0	.210	21.02	2.70	2.13	.0	18.4	
1405.0	BROKEN	17.73	2.70	2.22	.8	35.5	
1415.0	.150	20.42	2.61	2.08	24.9	12.2	
1425.0	.060	16.72	2.64	2.20	1.1	25.4	
1435.0	.080	17.82	2.62	2.16	27.3	22.4	
1445.0	.450	25.95	2.62	1.99	30.4	7.0	
1455.0	.070	18.97	2.61	2.12	23.7	12.1	
1465.0	.660	25.75	2.61	1.94	38.1	14.3	
1475.0	.350	21.74	2.63	2.06	29.4	8.0	
1485.0	.170	19.32	2.66	2.15	27.9	13.2	
1505.0	.220	14.97	2.68	2.28	14.1	29.4	
1515.0	.210	19.97	2.65	2.12	25.1	6.7	
1525.0	.230	20.90	2.65	2.10	8.8	17.4	
1535.0	.240	19.09	2.66	2.15	20.8	29.8	
1545.0	.360	18.27	2.66	2.18	2.2	34.0	
1555.0	2.650	24.29	2.66	2.02	30.0	18.2	
1565.0	.400	22.96	2.66	2.05	28.2	11.7	
1575.0	1.590	15.58	2.72	2.30	.9	38.4	
1585.0	.030	15.70	2.71	2.29	1.2	42.5	
1595.0	.090	15.97	2.69	2.26	.3	32.1	
1605.0	.210	17.67	2.66	2.19	15.4	22.3	
1615.0	.370	15.66	2.67	2.25	9.5	12.4	
1625.0	BROKEN	16.63	2.67	2.23	.3	46.4	
1635.0	.360	18.04	2.74	2.24	1.8	27.6	
1645.0	1.400	19.38	2.64	2.13	22.8	3.9	

LOGAN #1 (CON'T)						
1655.0	3.590	22.18	2.71	2.11	4.6	8.9
1665.0	.110	16.74	2.67	2.23	9.1	32.7
1675.0	1.420	14.71	2.73	2.33	.0	26.2
1685.0	2.930	16.93	2.75	2.29	1.2	33.2
AVERAGES	.672	18.86			12.9	

WELL: LOGAN #1
LOCATION: LOUISIANA
(DEPTH IN FEET)



Department of Energy
Bartlesville Energy Technology Center
P.O. Box 1398
Bartlesville, Oklahoma 74003

June 25, 1981

Mr. Donald F. McCarthy
McCarthy Engineering/Construction, Inc.
3635 South Sheridan
Tulsa, OK 74145

Dear Mr. McCarthy:

This is in response to your June 22, 1981 inquiry as to the availability of Department of Energy funds for your proposed oil mining project in Caddo County, Louisiana.

The oil mining concept has been investigated for and by the Department over the last few years with generally favorable reports. The plan you previously submitted is consistent both in location and method with one such report which was completed in April 1980 and listed prime reservoir candidates in the United States for oil mining projects. Also, your plan was considered to be an attractive prospect when reviewed by my staff.

However, as you probably know, our budget has been reduced to the level that funds are no longer available for cooperative financing of EOR projects. Therefore, we are unable, at this time, to provide monetary participation in your project.

Also, because your project has generated much interest within the group and because it parallels the goals of this organization, we would appreciate the opportunity to monitor your progress.

Sincerely,

Herbert B. Carroll

Herbert B. Carroll, Chief
Production Branch

ASSESSMENT OF U.S.A. RESIDUAL OIL RESOURCE AMENABLE TO MINING RECOVERY PROCESSES

LLOYD E. ELKINS

Petroleum Consultant

April 1980

ASSESSMENT OF U.S.A. RESIDUAL OIL RESOURCE AMENABLE TO MINING RECOVERY PROCESSES

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Group I Low Gravity > 100' Thick
Group II Low Gravity 40' - 100' Thick
Group III Medium Gravity > 100' Thick
Group IV Medium Gravity 40' - 100' Thick
Group V High Gravity > 100' Thick
Group VI High Gravity 40' - 100' Thick

APPENDIX A By Tab

Data Base Description

34-803 O - 84 - 5

OBJECTIVES

The following objectives are addressed in this analysis:

(1) Make an assessment of the quantity of residual oil in the United States after recovery by primary and applicable secondary methods, which might be a resource target for several types of mining or tertiary aided mining recovery processes.

(2) Rate the identified fields (specific reservoirs) qualitatively as to mining applicability.

(3) Identify specific reservoirs that might deserve detailed study for possible early application of mining technology.

(4) Describe the principal reservoir parameters that will dictate selection and effectiveness of mining or tertiary aided mining processes.

(5) Specifically excluded from this assessment are those deposits of heavy oil or tar that have not been commercially developed as oil fields.

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RESULTS AND CONCLUSIONS

(1) The Residual oil resource left after primary and secondary recovery in United States reservoirs amenable to mining or tertiary aided mining recovery is estimated to be about 64 billion barrels located in some 94 different reservoirs.

(2) Fifteen of the 54 reservoirs analyzed in the sample are rated good to superior for mining related recovery operations. The others are fair or poor. For the total U.S. the good or better prospects extrapolate to about 25 reservoirs containing 15 to 20 billion barrels of residual oil resource. This is judged to be an attractive resource that warrants serious investigative comparison with other recovery options.

(3) Based upon the ratings developed in this report five reservoirs are identified as prime candidates for research and development of mining related processes. They are listed as follows:

			Resource Billion Bbls
*	Group I Page 80	Kern River, Calif.-Excellent	3.5
	Group II Page 63	Cymric, Calif. -- Superior	.18
	Group IV Page 57	Big Sandy, Kans. -- Good	.04
	Group VI Page 1	Caddo Pine, No. La.-Excellent	.97
	Group VI Page 33	Healdton, Okla. -- Good	.35

* See Part II for details on these reservoirs and Table I in Part I for ratings and related information.

(4) Mining recovery processes are frequently referred to as "Drip Drainage" with demonstrated and quantifiable flow rate characteristicts. Gravity head (effective height i.e. continuous pay thickness), permeability to the oil phase, and area of the pressure sink are critical factors not easily quantified.

(a) Bedding planes (very thin shale lamina) within a pay interval will serve as a no flow vertical barrier and may limit effective height.

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(b) Permeability to oil in a waterflooded, waterwet formation will be essentially zero; in oil wet formations never zero but low, depending on water flood intensity. Gravity drainage alone may be very slow or ineffective under these conditions.

(c) Drainage area can be increased by design of mining processes.

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CLARIFICATION OF TERMINOLOGY AND MAJOR ASSUMPTIONS

No judgment is offered on the credibility of mining systems that have been identified and evaluated for DOE in well documented studies.

Most reservoirs having sustained natural or stimulated production in the United States will have oil, water, and often gas under pressure sufficient to cause problems if shafts (especially tunnels) are driven through them.

This critique of mining for petroleum is directed essentially to those deposits where mining provides access to the oil deposit. The rock containing mobile oil, water, and some gas under varying levels of pressure is not removed (mined) for subsequent oil extraction. However, some of this type rock may be mined while constructing shafts, tunnels, etc., for access.

Concepts for first generation mining applications, used in assigning preferance ratings in this analysis, involve drilling lateral wells from a work room at the base of the steel lined shaft. These drill holes could radiate like spokes in a wheel out several hundred feet in all directions. No workmen would be exposed to the reservoir fluids under pressure.

The term tertiary is used in this analysis rather than enhanced. (The terms are usually interchangeable). Tertiary relates to a system of supplying energy and displacement fluids to mobilize and recover some of the residual oil resource left after primary and secondary. Mining by itself or mining, aided by tertiary, could enhance oil recovery from this resource. The resource target for mining or tertiary aided mining is identical to the tertiary resource target in those reservoirs passing the mining screen.

The tertiary assist to mining would most likely be steam: huff and puff in the low gravity reservoirs (Group I and II) and light oil distillation to mobilize trapped oil in Groups III, IV, V, VI.

Cost effectiveness of mining operations will limit the portion of this resource that ultimately will be reduced to recoverable reserves.

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SCREENING PROCEDURES

(1) The Lewin Big Field Data Base is judged to be the most complete and readily accessible source to use for approximating the residual oil resource target. The sample contains 839 reservoirs.

(2) A physical mining limitation specified a maximum temperature of 140° F -- 201 reservoirs qualify.

(3) Sandstone or chalk (carbonates excluded) having average net pay thickness in a single zone greater than 40 feet excluding offshore were selected -- 54 reservoirs qualify.

(4) The 54 reservoirs were divided into six groups with two thickness categories and three API gravity ranges.

(5) On a state by state weighting basis this 54 reservoir sample is estimated to be representative of some 94 reservoirs.

Methodology and detailed results are included in Part II.

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DISCUSSION

Mining for Enhanced Oil Recovery.

It is recognized that mining of formations for surface extraction which contain immobile hydrocarbon material has precedent and a proven technology which often supports economic feasibility. For example asphalt deposits, diatomaceous earth in California (Getty) and Athabasca Tar Sands in Alberta Canada are typical.

Essentially the mining processes under consideration in this analysis can be employed to greatly increase the density of "drain holes" and injection points (if needed) to more effectively and economically (hopefully) employ appropriate recovery programs. But still , these programs often require mobilizing the oil and moving it to "drain holes".

Downward vertical flow utilizing gravity forces is a classic option. Even where this can be effective, producing rates can often be accelerated utilizing displacement systems such as steam or gas cap pressure of some type.

Gravity drainage down dip in steeply dipping reservoirs where flow is parallel to"bedding planes" provides opportunity for very high recovery efficiency. Vertical drainage across bedding planes (even thin shale lamina) can be reduced to nil. However, if vertical joints are open and have permeability, oil moving laterally parallel to bedding planes can and will move downward by gravity to lower levels. But the oil still has to be displaced laterally out of matrix rock using energy and some type displacement fluid.

Since height of oil column is very important in controlling gravity drainage flow rates the "effective" height must be determined. Effective height is that interval having continuous vertical permeability not intercepted by impermeable beds (thin clay "streaks" or shale lamina e.g.). The

presence of these will serve as effective barriers to vertical flow. In some pay sections these can be seen on logs. But also, the impermeable streaks may be too thin to be observed with normal logging systems. Careful geological analysis of complete cores or a series of pressure differential tests between sets of perforations can confirm the presence or absence of such barriers. In any event, before a mining project is launched the effective height of the continuously permeable pay must be determined.

Another factor combined with effective height for gravity drainage is permeability to the oil liquid. In water wet reservoirs after waterflooding (where water has swept the formation) permeability to oil for gravity drainage will be essentially zero. If "oil wet" there will be permeability to oil but still a small fraction of the initial oil permeability. For gravity drainage, the bottom portions of a water flooded oil wet reservoir will have the lowest effective oil permeability; during water flooding oil has been driven laterally but also upward (due to gravity forces). Not so in water wet reservoirs.

Oil trapped in pores by water will not move out by normal forces causing pressure gradients. However, for tertiary assisted mining, steam through distillation and viscosity reduction could mobilize and speed up gravity drainage in both oil wet and water wet systems.

This is not to say that mining systems designed to take advantage of vertical gravity flow have no place. Systems designed to mobilize trapped oil and displace it to densely spaced pressure sinks (holes, fractures, tunnels etc.) may be able to make gravity enhance the operation.

There are reservoirs where the formations are highly porous and permeable through out the producing interval. The Yates reef limestone field in West Texas and some pinnacle reef structures in Canada are noteworthy examples. In these reservoirs gravity segregation drives contribute to achieve very high oil recovery. Frequently a partially active water drive coupled with an expanding gas cap, allows gravity to keep oil, gas, and water effectively vertically segregated. The oil interval is gradually

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squeezed down by withdrawals with very low residual oil left behind in the water and gas invaded intervals. Here there is good effective height but the effective oil permeability after gravity drainage in the expanding gas cap and in water invaded intervals above the original oil/water contact would be very low. This would seriously restrict gravity drainage flow rates in mining operations conducted after effective primary, secondary and perhaps some type tertiary, if at all feasible.

There are reservoirs which contain mobile petroleum where natural or artificial water drives have proven ineffective. Typical are fields containing heavy oils in California which have been subjected to steam huff and puff well stimulation treatments.

There are types of oil bearing formations where permeability is too low for effective water flooding, typical is the Sprayberry in West Central Texas and Chalk formations in Northern Louisiana and in the currently developing Austin Chalk trends. There are others also.

Considering the heavy oil type first (Group I and II reservoirs)

A mining strategy to get access to a large areal exposure for steam huff and puff treatment bears investigation. The oil is present (low residuals is not a problem). Steam huff and puff reduces viscosity and supplies energy (hot water flashing to steam upon pressure reduction).

A typical system could consist of a vertical access shaft through the oil formation, a work room at the base, laterally drilled holes radially out for perhaps 500 to 1000' (like spokes in a wheel). These could be completed with slotted liners traced with steam injection lines. Plumbing would be required to collect and sump the produced oil and water and pumps to deliver it to the surface. Such a system might drain up to 160 acres of a thick,permeable,heavy oil deposit, although smaller projects might be optimal. Presence of bedding planes (shale streaks e.g.) could reduce effective vertical contact i.e. drainage efficiency.

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High gravity oil reservoirs too tight for water flooding.

The Caddo Pine (Pine Island) North Louisiana Anona Chalk reservoir is the only listed reservoir in the sample (Group VI Page 1) which fits this category. This high priority, very low permeability chalk formation has residual oil saturation of about 40 % (80 % of initial), high relative permeability to oil, (but specific permeability is probably like .1 md or less). connate water at 50 % and immobile. The other 10 % must be gas and probably some segregated and some dispersed.

Drilling was heavily directed toward areas proven to have natural fractures. The reservoir storage volume is in the matrix with pressure sinks created in the fractures by well penetration and stimulation.

A mining strategy might be to construct suitable lateral holes extending from a work room at the bottom of a shaft. If these lateral holes could be constructed to permit creating new vertical fractures upward into the chalk, recovery efficiency and producing rates would be significantly enhanced. A steam assist by injection through old wells should be considered.

If proven successful the mining EOR target in this one field might be one third to one half of the 974 million barrels estimated residual oil at abandonment.

High gravity oil reservoirs floodable using tertiary processes.

Reservoirs in Groups V and VI (except for Caddo Pine in Group VI) are excellent candidates for intensive sweep enhanced water flooding followed perhaps by some selected miscellar type chemical floods.

These would normally be pursued before resorting to mining alone. However, mining might be used in conjunction with tertiary operations. The optimal (cost effective) drainage pattern provided by close spaced drilling from the surface versus lateral drilling from a mined shaft

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would dictate the preferred route.

All reservoirs (especially Group V $>100'$ thick) must be looked at carefully for shale streaks that would interfere with the gravity drainage mechanism required in most mining processes.

Medium gravity oil Reservoirs.

Reservoirs in Groups III and IV really fall in between the low and high gravity groupings. The recovery processes using mining would most likely be similar to applications in floodable high gravity reservoirs in Groups V and VI and do not bear repetition.

Rating of all reservoirs in the Lewin Data Base for Mining Related Recovery Processes.

Detailed printouts of data on qualifying fields are in Part II. They are divided into six Groups as follows:

Group I Low Gravity ($<21°$ API), Thick ($>100'$ Reservoirs -- 11 Reservoirs

Group II Low Gravity ($<21°$ API), Moderately Thick (40' - 100') Reservoirs -- 6 Reservoirs

Group III Medium Gravity (21 - 30° API), Thick ($>100'$) Reservoirs 2 Reservoirs

Group IV Medium Gravity (21 - 30° API), Moderately Thick (40'-100') Reservoirs -- 8 Reservoirs

(The four offshore reservoirs that meet this criteria have not been included)

Group V High Gravity ($>30°$ API), Thick ($>100'$) Reservoirs -- 7 Reservoirs

Group VI High Gravity ($>30°$ API), Moderately Thick (40' - 100') Reservoirs -- 20 Reservoirs

(The nine offshore reservoirs that meet this criteria have not been included)

Carbonate and offshore reservoirs were excluded from consideration. Most porosity in thick carbonate pay zones is highly stratified with very little chance for effective vertical flow across non-porous streaks. In these situations gravity drainage recovery processes implemented through mining would be quite limited. In some reef deposits stratification is less pronounced. There, gravity segregation employed in primary and secondary operations will leave very little oil for recovery by mining. Offshore reservoirs were excluded because of high mining cost and expected high primary and secondary recovery efficiency.

All sandstone or chalk reservoirs were selected that had less than 140° F bottom hole temperature and fit the two thickness catagories. Mining people set the temperature limit.

A pay thickness exceeding 100 feet was first suggested primarily because of the height factor in gravity drainage flow rates. The 40 to 100 feet thickness factor was added because "effective" height in some thinner pays may be as good as some segments of a stratified >100 foot thick pay.

This screening resulted in 54 reservoirs passing the screen. Data for each reservoir is placed in a standard one page format and included in Part II.

In order to rate mining potential as reflected by primary and secondary performance, certain key parameters were pulled off the reservoir data sheets and shown on Table I. A key number is in Column 4 which is the expected insitu oil saturation after applicable secondary operations. But very important is Column 4 divided by Column 3. This gives the remaining oil saturation in percent of the initial. This provides at least a quantitative index as to how much mobile oil, percentage wise, that might be left for applicable mining and mining aided by tertiary processes.

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This cannot be rigorous but the following table can be helpful:

Column 5		Number code
> .8	Superior	1
.7 to .8	Excellent	2
.6 to .7	Very Good	3
.5 to .6	Good	4
.4 to .5	Fair	5
< .4	Poor	6

To add a volume qualification to Column 5 it is multiplied by porosity Column 1. High porosity enhances Column 5 ratings and low porosity detracts. This is shown in Column 6 and is considered more controlling than Column 5 alone.

The following Table reflects such a scale:

Column 6		Number Code
> 30	Superior	1
25 to 30	Excellent	2
20 to 25	Very Good	3
10 to 20	Good	4
5 to 10	Fair	5
< 5	Poor	6

In arriving at the ratings in Columns 9, 10, and 11 -- Column 6 provides the base case estimate. Column 6 reflects an index of the oil water trapped plus mobile oil after primary and applicable secondary which is left for tertiary, mining, or some combination of mining and tertiary. The rating scale using Column 6, shown previously, is modified by judgment taking into consideration viscosity and depth. In so doing the three ratings--Columns 9, 10, 11 are developed.

Where mining is aided by tertiary, the mode most likely would be steam assisted. Where tertiary rates 4 or better and mining falls to

the 5 or 6 rating, mining in any form is deferred at least until new situations dictate otherwise.

Where mining alone, or in combination with tertiary, rates 4 or better it should be carefully compared with other options.

For the purpose of gaining mining experience there are several fields that could be earmarked where the chances for success are especially favorable. To these,detailed study might be directed. Refer to Table I.

In Group I (Low gravity, >100' thick) there are three fields that look very attractive for mining aided by tertiary (steam), Pages 80, 81, and 82. Also, one--Page 82 that might stand on mining alone.

In Group II (Low gravity, 40 -- 100' thick) there are four fields that appear very amenable to mining aided by tertiary (steam) Pages 61, 63 64, and 69. Also, three of them Pages 61, 63, and 69 might qualify for mining alone.

In Group III (Medium gravity >100' thick) only two fields are in the sample and neither appear to be mining candidates.

In Group IV (Medium Gravity 40 -- 100' thick) two appear attractive for mining assisted by steam (light oil distillation) Pages 47, and 57. Also, one might support mining alone -- Page 57.

In Group V (High gravity >100' Thick) none appear attractive to mining with or without tertiary.

Group VI (High Gravity 40 -- 100' thick) there are six fields that appear attractive for mining assisted by tertiary (light oil steaming) Pages 1, 2, 10, 11, 24, and 33. The same six might get by with mining alone.

In all six groups there are fifteen fields that seen amenable to mining assisted by tertiary. Of those fifteen perhaps eleven could qualify for mining alone.

LEE
April 1980

J. E. Elkins

PURPOSE

The purpose of this report is to transmit our survey of domestic crude oil reservoirs that might be amenable for mining enhanced oil recovery. The report includes:

- A tabulation of the total domestic target for oil mining.
- A disaggregation of the target by the key reservoir criteria governing suitability for mining.
- A geographical distribution of the target resource.
- Detailed data on the target reservoirs

Appendix A to the report provides a brief discussion of the Lewin Big Fields data base used for the analysis.

CRITERIA FOR SELECTION

The reservoir criteria used for the selection of target reservoirs that could be candidates for mining assisted enhanced oil recovery were as follows:

- Reservoir Temperature -- $\leq 140^{0}$ F
- Lithology -- Sandstone/Chalk
- Net Pay -- Category 1: > 100 ft.
  Category 2: 40-100 ft.
- Oil Gravity -- Category 1: $< 21^{0}$ API
  Category 2: $21\text{-}30^{0}$ API
  Category 3: $> 30^{0}$ API

PLANS FOR CONSTRUCTION
OF

OIL MINING

PINE ISLAND OIL FIELD

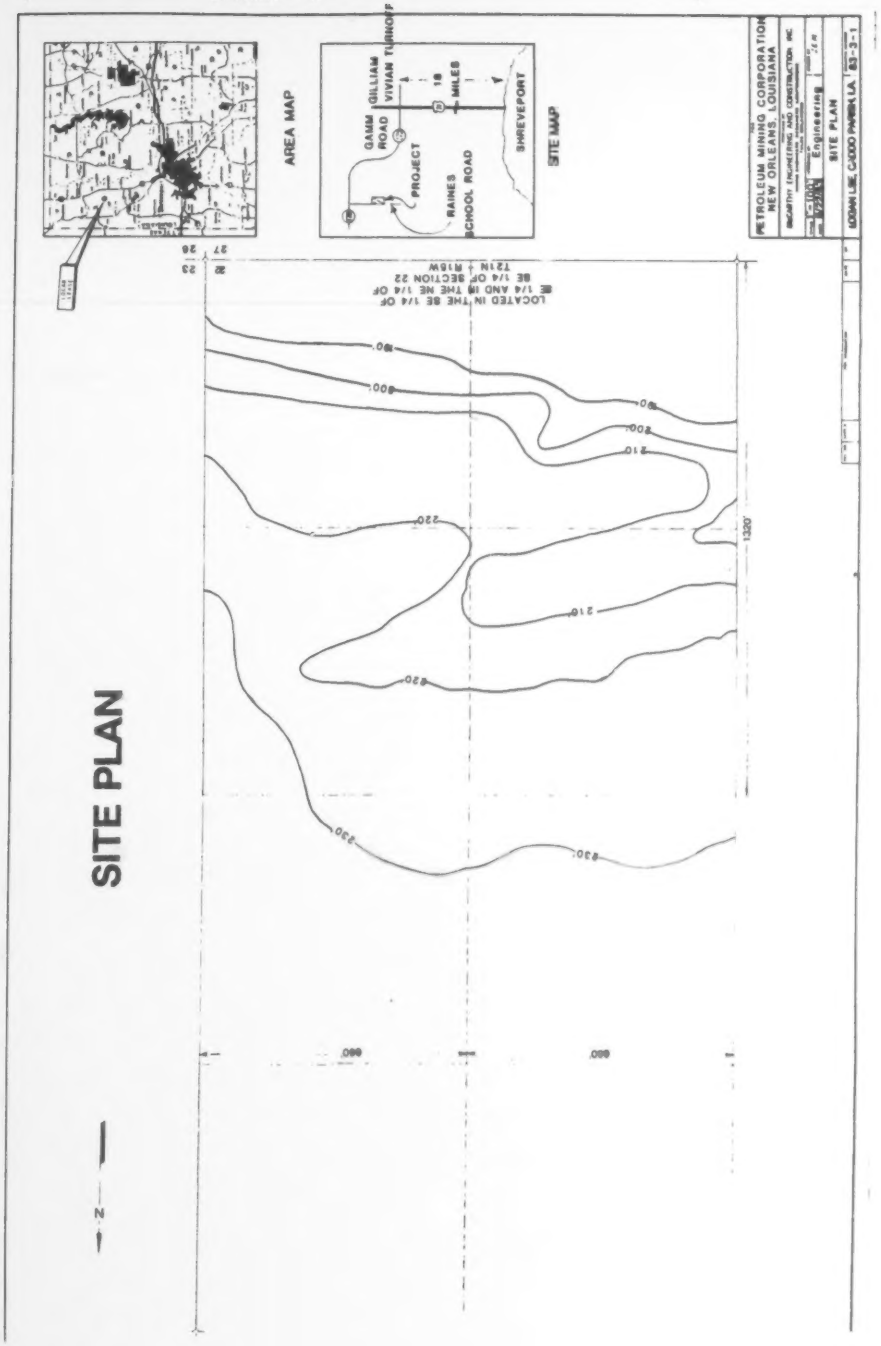
FOR

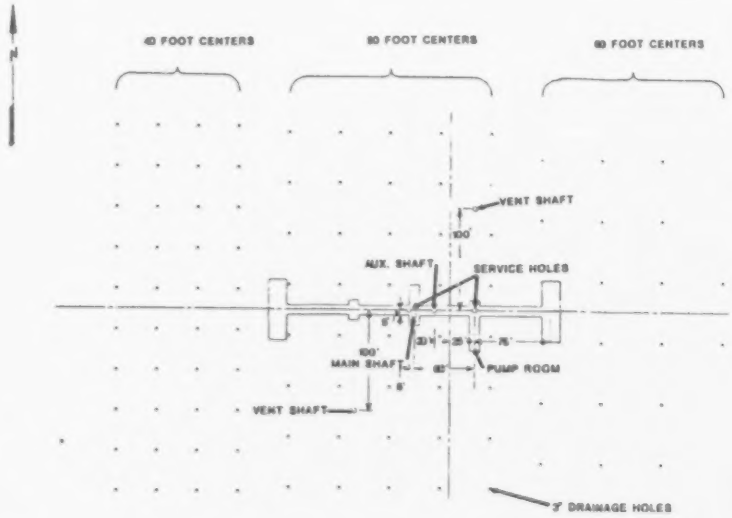
PETROLEUM MINING CORPORATION
NEW ORLEANS, LOUISIANA

LOGAN LEASE, CADDO PARISH,
LOUISIANA

PREPARED BY

McCARTHY ENGINEERING &
CONSTRUCTION, INC.
TULSA, OKLAHOMA


SITE PLAN
AREA MAP
SITE MAP
GILLIAM
VIVIAN TURNOFF
GAMM
ROAD
PROJECT
RAINES
SCHOOL ROAD
SHREVEPORT
18
MILES
PETROLEUM MINING CORPORATION
NEW ORLEANS, LOUISIANA
SITE PLAN
LOCATED IN THE SE 1/4 OF
SE 1/4 AND IN THE NE 1/4 OF
SE 1/4 OF SECTION 22
T21N - R15W
1320'
660'
660'
N



SPLIT SET

4'-0" CENTERS

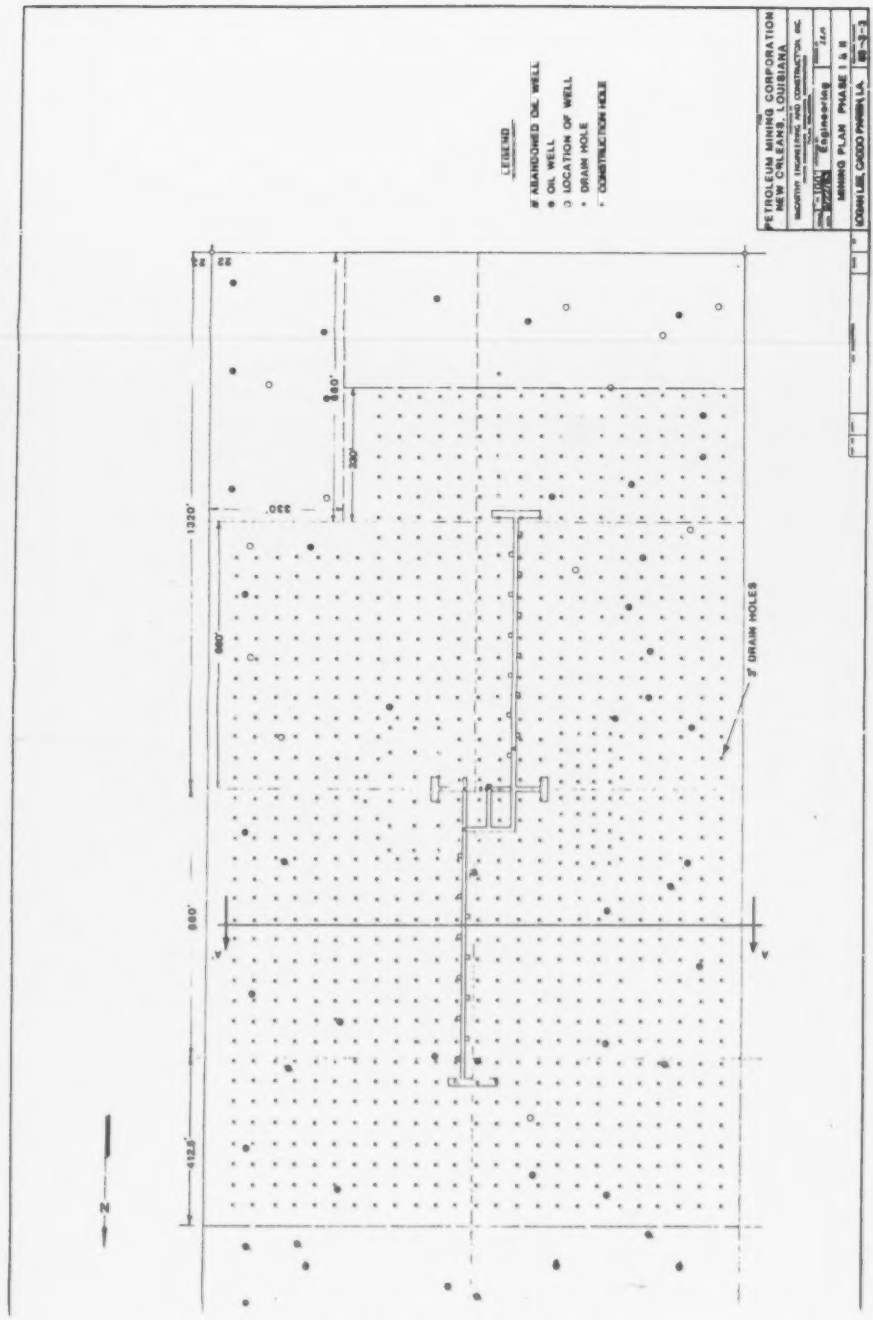
PETROLEUM MINING CORPORATION
NEW ORLEANS, LOUISIANA

McCARTHY ENGINEERING AND CONSTRUCTION INC.

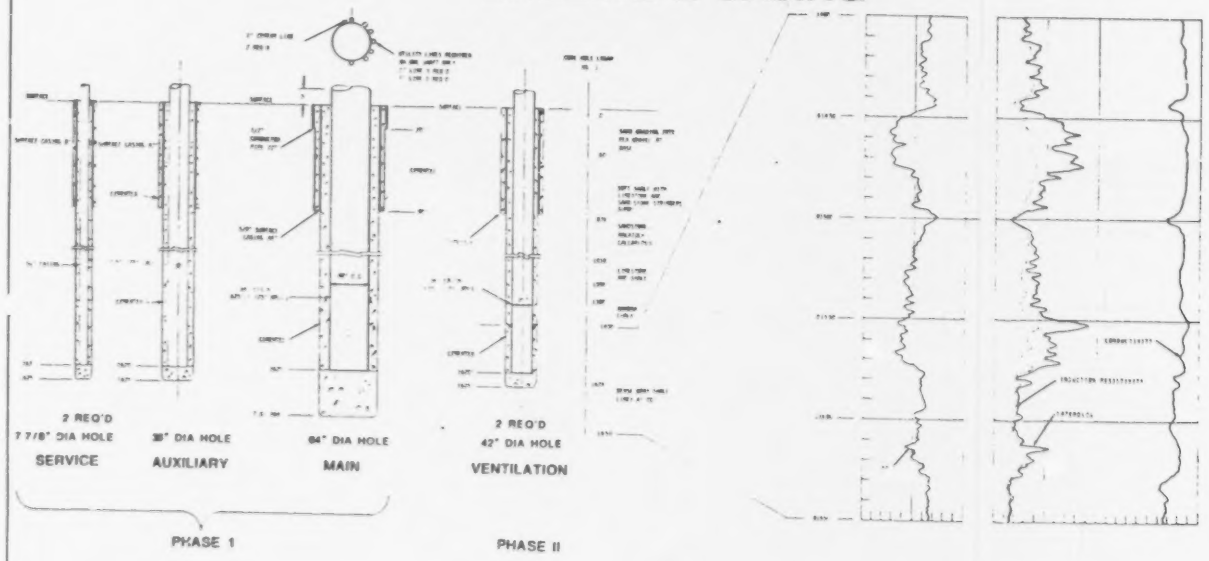
1"=100' | Engineering | J.A.M.

MINING PLAN PHASE I

LOGAN LBE, CADDO PARISH, LA. | 83-3-2

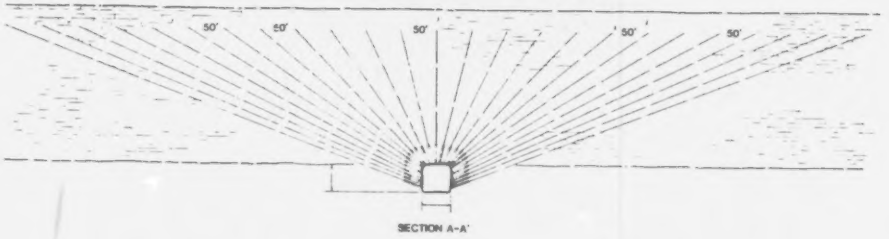

LEGEND
ABANDONED OIL WELL
OIL WELL
LOCATION OF WELL
DRAIN HOLE
CONSTRUCTION HOLE
PETROLEUM MINING CORPORATION
NEW ORLEANS, LOUISIANA
MINING PLAN PHASE I & II
KOONTZ LEE, CADDO PARISH LA
5' DRAIN HOLES
1320'
660'
330'
N

DRILLING & CASING

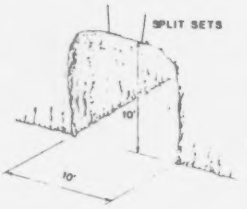


PETROLEUM MINING CORPORATI
NEW ORLEANS, LOUISIANA
McCARTHY ENGINEERING AND CONSTRUCTION
None
9/22/81
Engineering
DRILLING AND CASING PROGRA
LOGAN LSE, CADDO PAR, LA.
83-3

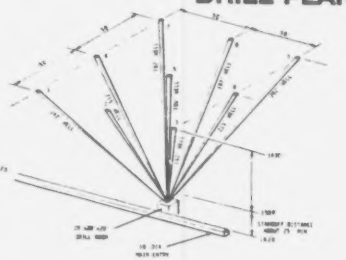
DRAINAGE PLAN



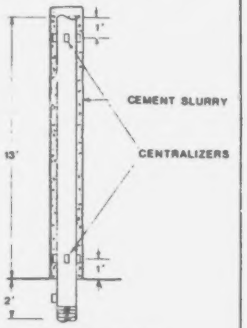
TUNNEL VIEW



DRILL PLAN

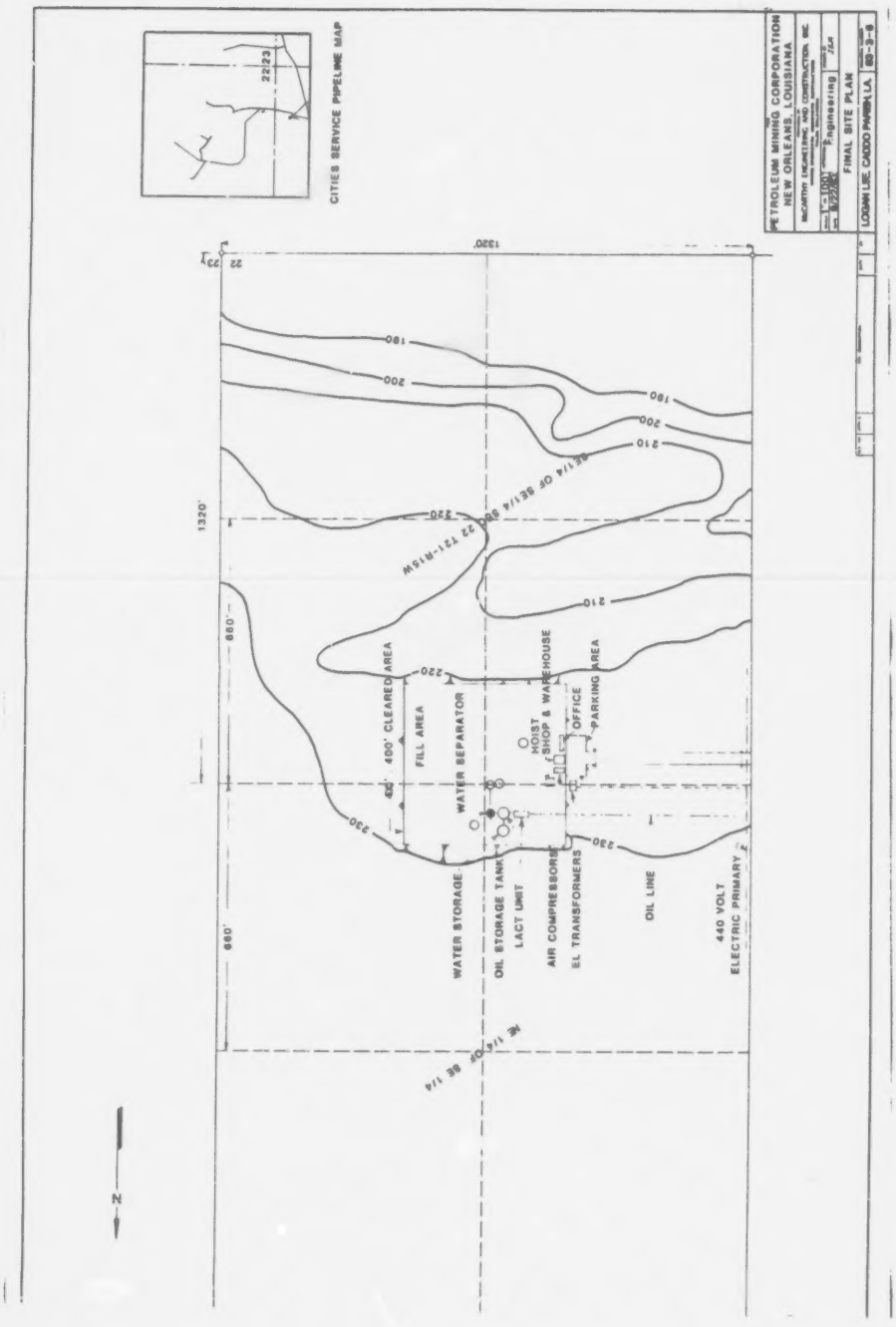


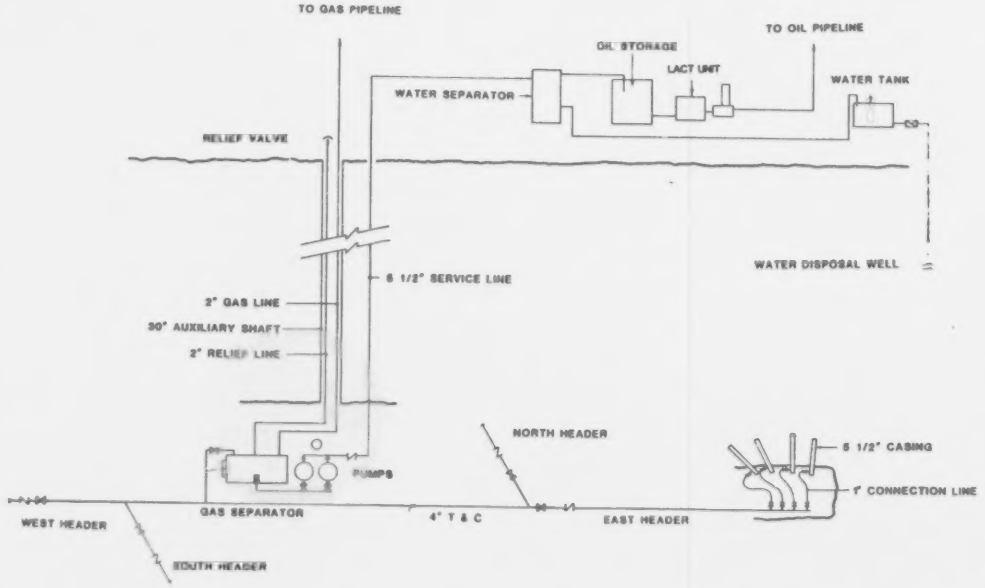
DRAINAGE HOLE



5 1/2" CASING W/ 2" COUPLING

PETROLEUM MINING CORPORATION NEW ORLEANS, LOUISIANA	
McCARTHY ENGINEERING AND CONSTRUCTION INC	
Date 8/22/83	Engineering
DRAINAGE DRILLING DETAILS	
LOGAN LSE, CADDO PARISH, LA.	83-3-5


PETROLEUM MINING CORPORATION
NEW ORLEANS, LOUISIANA
FINAL SITE PLAN
LOUAN LSE. CADDO PARISH, LA.
CITIES SERVICE PIPELINE MAP
22
23
1320'
880'
660'
180
200
210
220
230
320
400' CLEARED AREA
FILL AREA
WATER SEPARATOR
HOIST
SHOP & WAREHOUSE
OFFICE
PARKING AREA
WATER STORAGE
OIL STORAGE TANK
LACT UNIT
AIR COMPRESSORS
EL TRANSFORMERS
OIL LINE
440 VOLT
ELECTRIC PRIMARY
NE 1/4 OF SE 1/4 SEC 22 T21-R15W
NE 1/4 OF SE 1/4
N



PETROLEUM MINING CORPORATION
NEW ORLEANS, LOUISIANA

McCARTHY ENGINEERING AND CONSTRUCTION INC

Engineering

SCHEMATIC

LOGAN LEE, CADDO PARISH, LA. 83-3-7

McCARTHY
ENGINEERING/CONSTRUCTION, INC.

PETROLEUM MINING CORP.

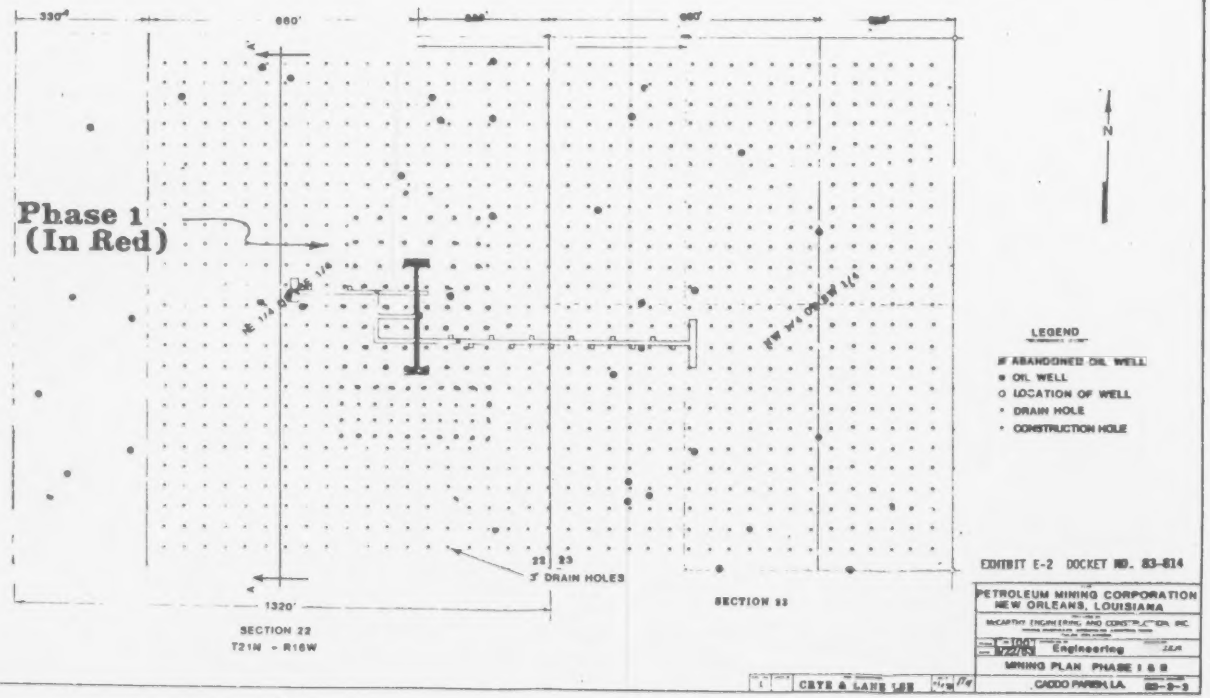
ANNONA CHALK
PINE ISLAND OIL FIELD
CADDO PARISH

DOCKET NO. 83-814

November 30, 1983

3635 S. SHERIDAN ■ TULSA, OKLAHOMA 74145 ■ 918 622-9646

EXHIBIT "E-2"


330'
660'
660'
Phase 1
(In Red)
NE 1/4 SECTION 1/4
NW 1/4 SECTION 1/4
N
LEGEND
ABANDONED OIL WELL
OIL WELL
LOCATION OF WELL
DRAIN HOLE
CONSTRUCTION HOLE
22 23
3' DRAIN HOLES
1320'
SECTION 22
T21N - R16W
SECTION 23
EXHIBIT E-2 DOCKET NO. 83-814
PETROLEUM MINING CORPORATION
NEW ORLEANS, LOUISIANA
Engineering
MINING PLAN PHASE I & II
CADDO PARISH, LA.
CRYE & LANE LEE

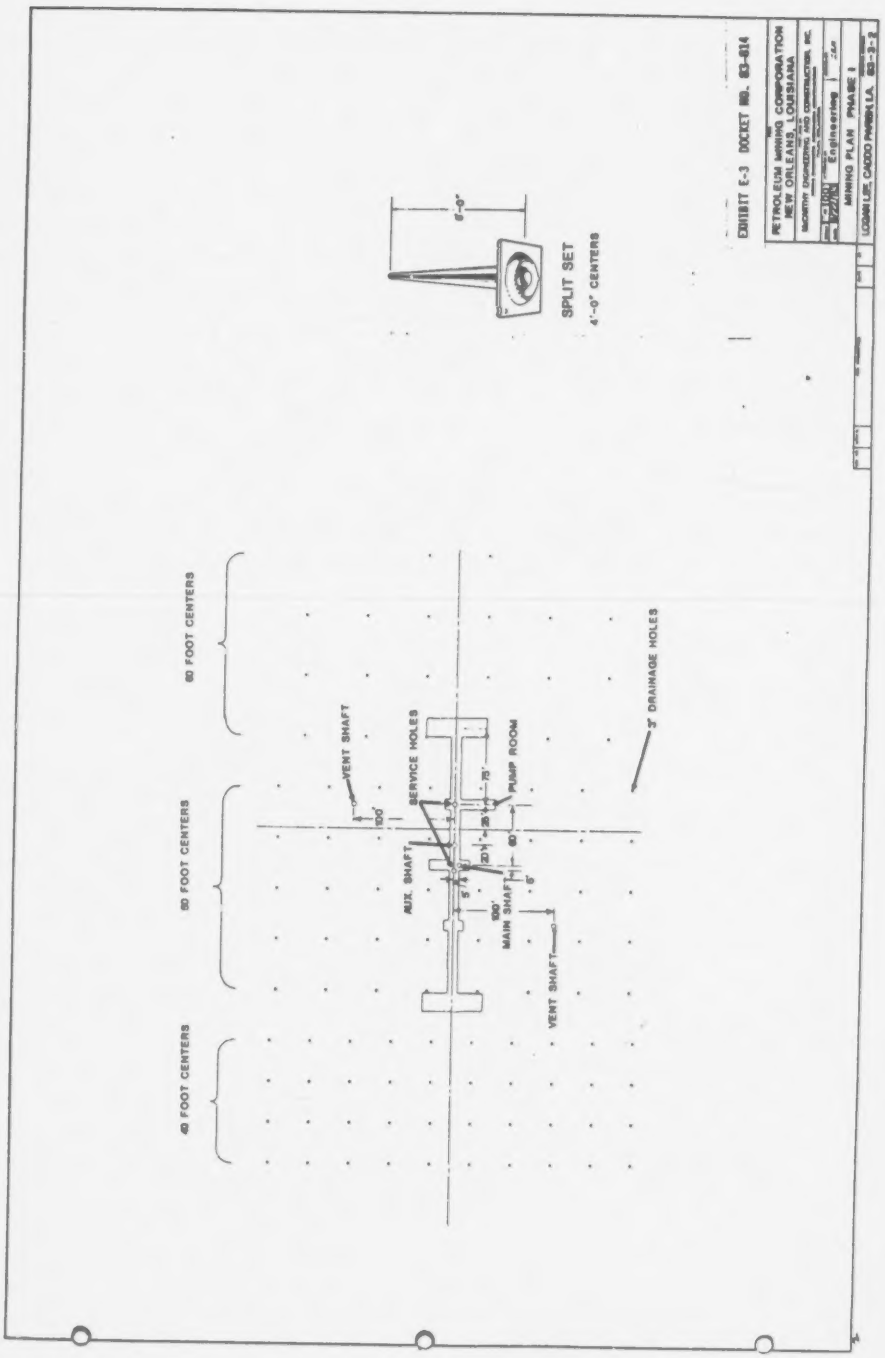
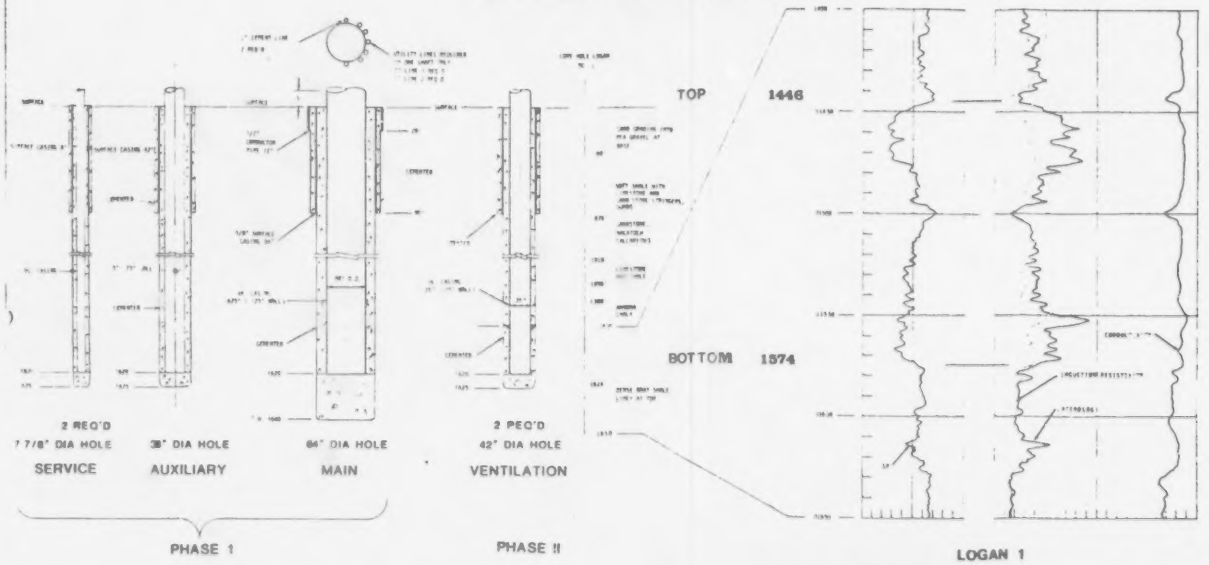


EXHIBIT E-3 DOCKET NO. 83-814
PETROLEUM MINING CORPORATION
NEW ORLEANS, LOUISIANA
MINING PLAN PHASE I
LOGANSPORT, CADDO PARISH, LA. 83-2-2
SPLIT SET
4'-0" CENTERS
6'-0"
40 FOOT CENTERS
80 FOOT CENTERS
80 FOOT CENTERS
VENT SHAFT
SERVICE HOLES
AUX. SHAFT
MAIN SHAFT
VENT SHAFT
PUMP ROOM
3" DRAINAGE HOLES
100'
150'
20'
60'
6'
5'

DRILLING & CASING



NOTE: At termination of project all drainage holes shall be completely filled with cement. The main shaft and ventilation holes shall be filled with sand and then capped. No casing shall be pulled.

EXHIBIT E-4 DOCKET NO. 83-

PETROLEUM MINING CORPOR
NEW ORLEANS, LOUISI
MURPHY ENGINEERING AND CONSTRUCT
Engineering
DRILLING AND CASING PRO
CADDO PAR LA.

NOTE

EXHIBIT E-5 DOCKET NO. 83-814

FOR
PETROLEUM MINING CORP
NEW ORLEANS, LA

PREPARED BY
McCARTHY ENGINEERING AND CONSTRUCTION, INC.
MINING ENGINEERS DESIGNERS CONTRACTORS
TULSA, OKLAHOMA

SCALE None	APPROVED BY	DRAWN BY JTM
DATE 11/15/83		

WEST EAST X-SECT

CADDO PARISH, LA.

DRAWING NUMBER 83-3-8

REV NO	APPV D	REV. DESCRIPTION	DATE	BY

88

EXHIBIT "F"

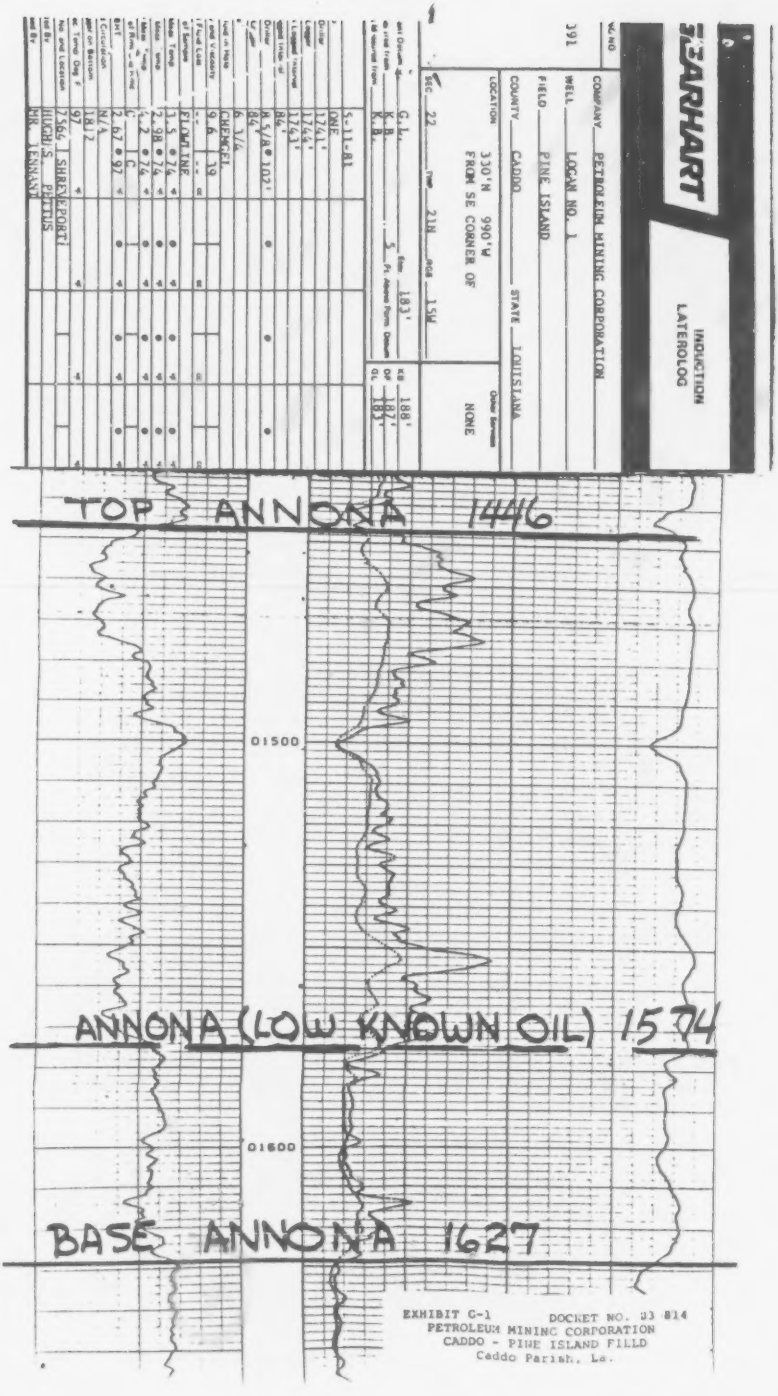


EXHIBIT C-1 DOCKET NO. 93 814
PETROLEUM MINING CORPORATION
CADDO - PINE ISLAND FIELD
Caddo Parish, La.

EXHIBIT "G"

LOGAN #1 (B-24)
Pine Island-Annona Chalk
Drilled 1981
Figure 1

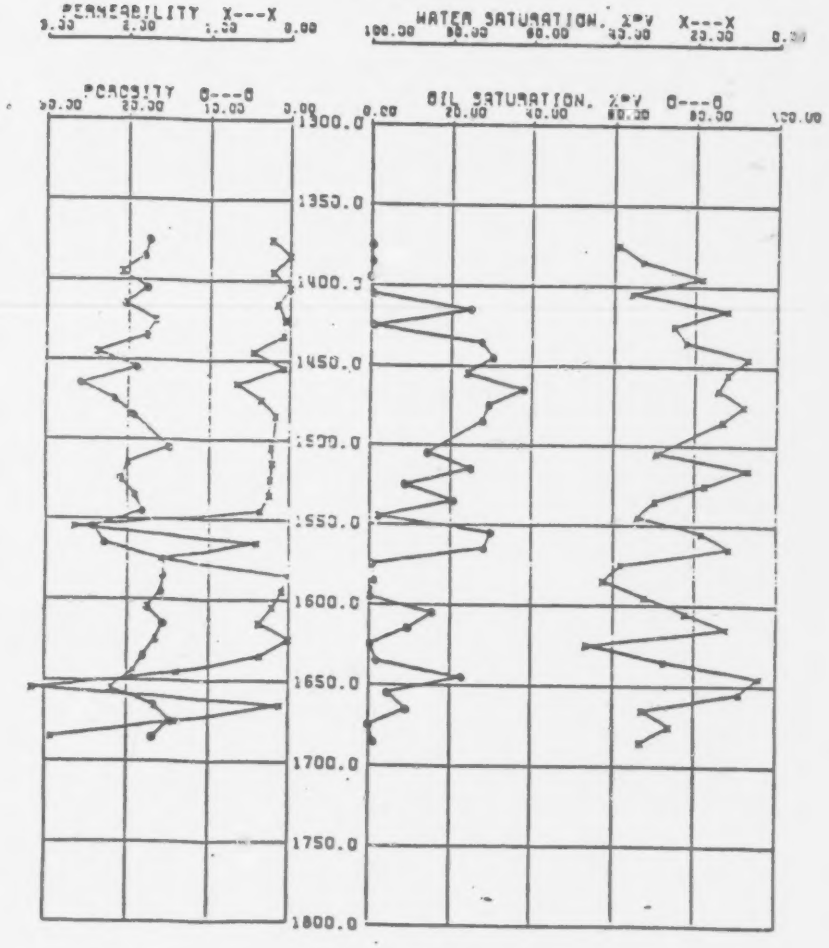


EXHIBIT G-2 DOCKET NO. 83-814
PETROLEUM MINING CORPORATION
CADDO - PINE ISLAND FIELD
Caddo Parish, La.

LEE/4-18-83

EXHIBIT "H"

STATE OF LOUISIANA
OFFICE OF CONSERVATION
BATON ROUGE, LOUISIANA

December 27, 1983

ORDER NO. 122-H-f

Order concerning the application of Petroleum Mining Corporation for authority to conduct underground oil and liquid hydrocarbon mining operations and to establish rules and regulations incident thereto in the CADDO - PINE ISLAND FIELD, Caddo Parish, Louisiana.

* * * * * * * * * *

Pursuant to power delegated under the laws of the State of Louisiana, and particularly Title 30 of Louisiana Revised Statutes of 1950, and after a public hearing held under Docket No. 83-814 in Baton Rouge, Louisiana, on November 30, 1983, upon the application of Petroleum Mining Corporation, following legal publication of notice and notice in accordance with rules prescribed by the Commissioner of Conservation, the following order is issued and promulgated by the Commissioner of Conservation as being reasonably necessary to conserve the oil and gas resources of the State, to prevent waste as defined by law, to avoid the drilling of unnecessary wells and, otherwise, to carry out the provisions of the laws of this State.

D E F I N I T I O N

The Annona Chalk, as used herein, is defined as that oil bearing reservoir encountered between the electric log depths of 1446 feet and 1574 feet in the Petroleum Mining Corporation - Logan Well No. 1 located in Section 22, Township 21 North, Range 15 West, Caddo Parish, Louisiana.

F I N D I N G S

The Commissioner of Conservation finds as follows:

1. That all available geological and engineering data indicate that the program of underground oil mining contemplated by the applicant appears to be economically feasible, is reasonably necessary for the prevention of waste and the drilling of unnecessary wells, will appreciably increase the ultimate recovery of oil and liquid hydrocarbons from the Annona Chalk, and should therefore be approved and adopted.

2. That the authority herein granted should be restricted to the Annona Chalk within the area included within the unit established by the Unit Agreement entered into by the applicant and other parties, Petroleum Mining Corporation Exhibit No. L-5 for Docket No. 83-814, a plat of which unit is attached hereto and made a part hereof.

3. That there should initially be granted to the operator a total of 100 drilling permits for the first 100 underground wells to be drilled pursuant to this program, which proposed wells shall be located as shown on Petroleum Mining Corporation Exhibit No. E-2 for Docket No. 83-814.

4. That thereafter, upon application to the District Manager of the Shreveport District of the Office of Conservation, and without the necessity of a formal hearing, additional permits may be granted for the drilling of additional such wells using the same or a similar spacing pattern within the limits of the said voluntary unit, reference Finding No. 2 above.

5. That the available data also indicate that there should be no spacing rules for production wells except for those wells located in the vicinity of competitive lease or unit lines, in which case production wells must be located a distance of at least 50 feet from the competitive lease or unit lines.

6. That Petroleum Mining Corporation should be designated as operator of the mining project authorized herein and as the party responsible to the Commissioner of Conservation for operating in accordance with the rules and regulations governing such project as established hereby.

O R D E R

NOW, THEREFORE, IT IS ORDERED THAT:

1. There is hereby authorized a program of underground mining for the production of oil and liquid hydrocarbons from the Annona Chalk in the Caddo - Pine Island Field within the area depicted on the plat which is attached hereto and made a part hereof, operations under such program to be conducted in accordance with the testimony and exhibits presented by Petroleum Mining Corporation at the public hearing held under Docket No. 83-814, above referred to.

2. Permits for the drilling of the initial 100 production wells under this program are hereby granted in accordance with Finding No. 3 above.

3. Additional permits may be granted thereafter in accordance with Finding No. 4 above.

4. Spacing rules for wells located in the vicinity of competitive lease or unit lines are hereby adopted in accordance with Finding No. 5 above.

5. Petroleum Mining Corporation is hereby designated as operator of the mining project authorized herein in accordance with Finding No. 6 above.

This Order shall be effective on and after December 1, 1983.

OFFICE OF CONSERVATION
OF THE STATE OF LOUISIANA

Patrick H. Martin
PATRICK H. MARTIN
COMMISSIONER OF CONSERVATION

FB

Petroleum Mining Corp.
Exhibit A-Attached

S

TOWNSHIP 21 NORTH, RANGE 15 WEST

SECTION 22
SECTION 23
Socony Mobil Oil Co. Inc.
"D H Raines MR"
Thall Oil Co. Ltd.
M K Beshara MR
L L Robinson
Amoco Prod Co Ltd
The Texas Co
"Fee"
Caddo Min. Ltd Co MR
A W Baird, M J Henley & W H Pow
Johnson, prop of Stevens McPrige & Palmer P. Wood's Etal
Star-Falcon Oil Co
Lee Raines, Clay, Mary Ann Raines Johnson
Joe Raines, etal
Thall Oil Co Ltd, Ark Fuel Oil Co pr
"Crye MR"
C W Lane, Jr etal
C W Lane &, Fannie S. Pitchman &
Texaco, Inc
Caddo Mineral Lease Co MR
Mrs Fannie B. Hickman &
Marslow Oil Corp &
Thall Oil Co Ltd.
C.L. Morris Ltd MR
C. L. Thomas
W. E. Logan, MD
B W Humphrey & Wm L Gal
W W Kay &
C W Cox Est &
W. D. Briggs Jr
Watkins &
Effie Nixon &
Texaco, Inc Co
Sam Shiar Ltd.
Watkins - Lane MR
W H Adkins
Effie Nixon
C W Lane &, Fannie S. Pitchman &
& Mabel H. Fields &
Marslow Oil Co, Inc &
Mrs Mamie J Dees &
Mrs M J Jackson
BLACK

EXHIBIT "A"
PETROLEUM MINING CORPORATION- ORDER NO. 122-H-1
LANE/CRYE VOLUNTARY UNIT A
SECTIONS 22 and 23, TOWNSHIP 21 NORTH,
RANGE 15 WEST, CADDO PARISH, LOUISIANA

34-803 O - 84 - 7

Senator WARNER. You are to be commended for your initiative. While it is a technique as you said that has some historical precedence, operating precedence, it is a good old-fashioned American capital risk venture that you are involved in.

Mr. BURLINGAME. That is right.

Senator WARNER. Do you want to put that on the record more forcefully?

Mr. MILLER. I said that is very correct. We have been working on this for a number of years. We have had a lot of obstacles thrown at us from people who were not very enthusiastic about it, but that has changed dramatically in the recent past.

We honestly believe that our money and our partners' money is going to, hopefully, demonstrate that.

Senator WARNER. What do you do with all of the waste material you remove from the Earth to create these passes?

Mr. BURLINGAME. We are required to dispose of them. Actually the dirt is pretty easy to dispose of. You can do that onsite. But when you go through the oil bearing formation that has to be disposed of to not affect the ecology. What we do is give it to the State and they make roads out of it.

Senator WARNER. Oh, really.

Mr. MILLER. That particular substance will be disposed of as we go through the oil bearing zone in the special disposal sites that are so designated by the State.

Senator WARNER. The State environmental people have passed on all of this?

Mr. MILLER. Yes, they have.

Senator WARNER. Gentlemen, we appreciate this. Is there anything further you wish to put in the record?

Mr. BURLINGAME. I think, Senator, this says it all.

Senator WARNER. That sounds like hard work. Good luck and thank you very much.

We will now have our second panel. Mr. Wimpfen; Dr. Fine of Cambridge, Mass.; Mr. Hyland of Washington, D.C.; Dr. Trent, Pittsburgh; and Mr. Spence, Houston, and you will also be joined by Ms. Cobb, who I understand is with Dr. Trent.

Mr. Wimpfen, you sort of started this off sometime ago. Do you want to lead off?

STATEMENT OF SHELDON P. WIMPFEN, MINING ENGINEER, LURAY, VA.

Mr. WIMPFEN. Thank you, Mr. Chairman. I appreciate the opportunity to meet with you again on this important topic and I only wish you had more of your colleagues here so they could hear this. I know that you know a lot about it already.

My name is Sheldon Wimpfen. I am a 1934 graduate of Texas College of Mines and Metallurgy, the University of Texas. Except for a few years as associate professor at Texas A&M and captain in the Marine Corps in World War II, my entire life has been involved in exploration and mining and the processing of minerals.

I have worked in a wide range of tasks from mucker to timberman, to miner, geologist to engineer, mine engineer, vice president,

president of mining companies. I have worked in grain, coal, tin, copper, lead, zinc, and gold and silver.

In 1970, I terminated my corporate activities and went to work for the Bureau of Mines as an assistant director and stayed there until I retired in 1980 as chief mining engineer. Currently I serve on the National Defense Executive Reserve and on the National Academy of Science and Tunneling Technology Committee. I am working as a consultant and my principal consultants have been the World Bank and an Air Force contractor and a number of other private clients.

A lot of my time I have been spending on this particular subject at my own expense. I am a licensed professional mining engineer in Colorado and the District of Columbia. I am here today to represent myself and some 230 million Americans whose livelihood and survival depend upon the economic supply of liquid energy. I believe that our survival as a nation depends on a large and adequate supply of liquid energy to provide the tactical movement for our Army, Air Force, Navy, and the Marine Corps.

In the early 1960's I became impressed with the disparate recover experienced by the metals and mineral industry and that of the petroleum industry. Lithium, copper, lead, zinc, it is common to get recoveries that are close to 90 percent. While the petroleum industry has been characterized by a 30- to 40-percent recovery, probably closer to one-third on the average.

This slow recovery probably stems from petroleum's abundance. We have always had through the centuries an abundant supply of petroleum. Petroleum mining is probably one of man's earliest activities. Mining parallels man's history ever since 5000 B.C., when the Egyptians used bitumen to mummify their pharaohs and other people. The Persian word for bitumen is mumiai from which the word mummy is derived. Moses' bulrush cradle was covered with bitumen.

At about 450 B.C., Herodotus cited a place near Susa, Persia where oil, salt, and bitumen were extracted from shallow shafts and short drifts.

As the population of the world grew and as demand increased, there were more sophisticated methods used. It was used, as Mr. Burlingame cited, in Germany, France, Japan, and a number of other places. It was mined in Trinidad and caulked ships and in many places throughout the United States.

There are still a few of these active bitumen mines where locally mined material is produced to use on the roads. I know of one in Utah and there are several in Tennessee and Kentucky.

To get the liquid energy, the earliest records in the United States are probably that of the geological survey of Ohio, which cites an 1865 effort to get oil near Markburg and it was successful, and in Ventura, Calif.; Sulphur Mountain, there were some 30 drifts that were driven into the pool and the oil was allowed to seep in gradually by gravity. That operation continued for a large number of years.

Along came a man with a better idea, Edwin L. Drake, of Titusville, 1859, who drilled a well and it gushed oil from the shallow fields up near Titusville.

Oil was so cheap to produce and the demand was not that great that oil mining just fell into a decline and all of our oil came to be produced from wells. In fact, there was so much that they gave away lamps, for example, oil for the lamps in China. Lamps were given to the Chinese to promote their use of kerosene, because at 10 to 15 cents a barrel, there was a tremendous surplus of liquid petroleum.

There was an abundance. It was a cheap fuel and I think a lot of us here remember not too long ago there was a power race on and automobiles just grew with abandon and had higher horsepower and used more energy and got bigger and bigger. No one gave a thought to it. There really was not any reason to give a thought to how much energy a gasoline engine would use. Oil was selling for a dollar a barrel and there was more than enough to go around, and this was way down on the priorities, the job of trying to make a more efficient gasoline engine.

There were some countries that were not oil rich. I mentioned Pechelbronn in France, Wietze in Germany, and a few other locations. In 1925 the then Director of the Bureau of Mines, H. Foster Bain, took a trip to Europe and saw these mines and directed George Rice, then chief mining engineer of the Bureau, to make a study of this thing. In 1932, the study of petroleum mining methods was published as bulletin 351. It came to a number of conclusions that were valid then and are valid today.

What one is that he pointed out that you had to be aware of what you were getting into with respect to gas, the depleted pool with the ratio of water to oil and he thought you should not try to go more than 4,000 feet deep, because that was the depth to which coal was being mined in Europe at that time.

But one of his most interesting observations, he said essentially forget oil. It is never going to be done until the wellhead price of oil exceeds $2.25 a barrel and that was when oil was selling for 10 to 15 cents for a 42-gallon barrel. However, he concluded on another point. He said every effort ought to be made to keep on top of this situation and some day get at the 60 to 80 percent of this natural resource that is being left in the ground after all of the pumping methods are applied.

Well, new oilfields continued to be discovered, new techniques developed, new technology. I made a study in 1956 when I was employed in coal mining. I predicted that oil production in the United States would peak in 1970. Unfortunately, I was right, but imports of petroleum were really going up and they went from 4.74 million barrels a day up to 8.81 million barrels per day in 1977 and they have since declined in 1982 to a little more than 5 million barrels a day, showing that we have achieved considerable success in reducing our demand.

In 1972, a witness who is not here unfortunately today, Earl Herkenhoff, published a paper in the Engineering and Mining Journal "When Are We Going To Mine Oil?" and he wrote that when oil was selling for $2.50 a barrel and then right after he wrote and published that article, lightning struck with OPEC oil.

I was with the Bureau of Mines then and we could see that there were going to be some significant impacts from higher prices of oil. So I had some of my staff prepare a paper on the impacts, and you

might laugh at these numbers, 60 cents, 80 cents, and $1 a gallon gasoline and this study showed that copper, aluminum, lead, and zinc and all of the other component metals of the automobile would decline substantially, actually by 15 percent, 26 percent, and 35 percent respectively.

If you look at these mining industries today, you can see that these figures and projections were pretty close. But when the embargo came on, I reviewed the old report by George Rice and urged a restudy of petroleum mining and two studies for a gross amount of about $371,000 was conducted, one by Golder Associates and the other by Energy Development Consultants. These reports were finally published in 1978 and brought the whole picture of oil mining into sharp focus.

One of the most pertinent pieces of information that came out of these reports was the size of the target that is available to us. Updating those figures slightly, the original oil endowment of the United States onshore, not the offshore oil, but the land-based oil resource was 450 billion barrels, that producible by conventional methods; primary at about 17 percent; secondary about 17 percent; and tertiary less than 5 percent would aggregate 175 billion barrels producible by conventional methods.

Of that we have already produced 125 billion barrels, leaving 50 billion to be produced by these conventional methods. Subtraction shows that we have a resource then of some 275 billion barrels, much of which can be a target for oil mining.

If we pursue the course of oil mining, the technological economic indications are that fourth order recovery might make 25 to 30 percent of that available, but the political economical impacts would be staggering and our national reserves would be doubled. If we are going to get into oil, we have to know a number of disciplines that are involved in producing our mineral resources.

Petroleum engineers know all about velocity, oil head pressures, rate decline curves, and those kind of things, but most of them do not know a blessed thing about sinking shafts, driving drifts, and drilling the shallow up-holes that would be required by the type of mining, essentially that which was described by Mr. Burlingame.

So while the fourth order technology that is completely different from the conventional generic technologies of primary and secondary and tertiary—primary and secondary, adding new energy to old reservoirs; and tertiary which is modifying fluid properties to achieve a higher displacement efficiency, is going to be a somewhat different technology than we have had before.

There are several unique characteristics. Unlike the first three orders that require us knowing of the two disciplines of the mining and petroleum engineers, neither can work autonomously and do the job. Everything in the primary, secondary, and tertiary methods is conducted from the surface with deep holes, while primary methods require the people go underground and drill shallow up-holes at various angles.

Also, unlike the first three orders, primary, secondary and tertiary, 17 percent, 17 percent and less than 5 percent, oil mining will recover more residual resource than all three of those put together and it has to justify the substantial capital expense and operating expense in going after this national aspect.

We need to do this regardless of that cost, even though that cost is significantly less than that of synfuels and less than that of shale rock. We know where this resource is. It is the same plus 25-degree API oil that is the feedstock up and running refineries. In most cases the transportation systems remain intact and are there to handle this, if you will pardon the expression, new source.

It is really old oil geologically, but it is new in the sense but for the acquisition of this technology, this oil would not be produced. As far as I know to date, the IRS has taken the position that this is old oil which it is geologically. We cannot deny that. But the taxes on old oil are up to $9 a barrel and that can be a very potential deterrent to having the level of old-oil mining that we need. Because unlike conventional primary and tertiary methods that require expensive drill holes, oil mining requires even more front-end expense before you can get into the job and do it well.

Currently, I do not imagine there are any publicly available figures. The available data rests in the hands of the people that are here today, some of them at this table, and others that are going into oil mining as a private industry undertaking. However, if you take the 1978 report by Energy Development consultants and update those, I do have some numbers. Those figures were developed for both a 100-foot, so-called depleted pool and 200-foot depleted pool, and updating these capital costs, I estimated it would take $50 million to $70 million to put in an oil mine, a 100-foot thick reservoir, and $43 million to $60 million for a 200-foot thick reservoir.

Those were the figures of 1978, and I updated them for 1983, $50 million to $70 million for a 100-foot thick reservoir and $55 million to $75 million for a 200-foot reservoir. I based that on a 10-percent-per-year inflation. From this scale of investment from a 100-foot bed, you could get about 14,000 barrels a day from a square mile and 55,000 barrels a day from a square mile of 200-foot thick reservoirs.

Over a projected 35-year life, a 100-foot reservoir would average 1,575 barrels a day, and the 200-foot thick reservoir would average 6,000.

If you look at the front-end money that is required to produce a million barrels a day and get that in perspective, while we import 5 million barrels a day now, and we use about 12, we have 7 produced domestically. So, if we wanted to replace about 1 million barrels of imports with 1 million barrels of mined oil, it would take 50 of these 20,000 barrels-a-day units and have a capital cost in the order of $3 billion.

From the operating cost standpoint, the 1978 estimates were $12.50 to $15.25 per barrel. Considering the inflation that has been happening since then, it is more likely that today's cost might be on the order of $20 a barrel, give or take $3 or $4. So you can see where the tax of $9 on old oil would make the cost with taxes exceed the $29 a barrel price a day.

However, the imposition of a more realistic tax would serve as encouragement. The average lifting cost of OPEC oil is more than $3 to $4 a barrel and from that you can see where we stand. This oil is here. It is known we can get it and we do not have to rely on imports that might jeopardize our economy at any time.

What we are going to do aside from reducing the risk of dependence on foreign sources, it would lower the inflation rates, increase employment, and increase the gross national product. For the time being we seem to be getting by in regards to oil supply. Maybe the closing of the Straits of Hormuz would not affect us too much, but it would affect some of our friends and we might have to do some diverting.

We have waited a long time before we have really faced up to the opportunity that presents itself by oil mining, but we now have the capability within our hands to avoid another liquid energy crisis.

Thank you, Mr. Chairman.

[The prepared statement of Mr. Wimpfen follows:]

OIL MINING

For Senate Subcommittee on Energy and Mineral Resources Hearing

March 2, 1984

Mr. Chairman, members of the Senate Subcommittee on Energy and Mineral Resources, I appreciate the opportunity to be here today to present my views on oil mining. My credentials for discussing this important topic follow:

My name is Sheldon P. Wimpfen, I am a 1934 graduate of the University of Texas, College of Mines and Metallurgy. Except for a few years as associate professor of Civil Engineering at Texas A & M College, and as a Captain in the U.S. Marine Corps in World War II, my working life has been in the field of minerals and mining. This activity spanned a wide range of tasks from mucker and miner through exploration and mining geology, mine engineer, to editor of a national mining magazine, corporation vice-president and president. In these roles my efforts were directed at the search for, mining and processing of a host of different minerals and metals including coal, uranium, copper, tin, aluminum, fluorspar and gold and silver.

In 1970 I left corporate activities to serve the U.S. Bureau of Mines as Assistant Director retiring in 1980 as Chief Mining Engineer. In 1980 I served on the Strategic Minerals Task Force of the President's Transition Team. Currently I serve in the National Defense Executive Reserve and the U.S. National Committee on Tunneling Technology of the National Academy of Science. My clients as a mining consultant include the World Bank, a U.S. Air Force contractor and a number of private clients. I am a licensed professional mining engineer in Colorado and the District of Columbia.

I'm here today to represent myself and some 230,000,000 Americans whose livelihood and survival hinge upon the economic supply of liquid energy. Indeed, our survival as a Nation depends in high degree upon ample supplies of petroleum for the tactical movement of our Army, Navy, Air Force and Marines.

In the early 1960's I became impressed with low recovery experienced by the petroleum industry in its production of one of our Nation's most important resources vis-a-vis the minerals industry where great effort and substantial investments are expended to achieve high level recoveries of the valuable minerals.

Recovery rates for selected materials are:

Tin 50 - 60%
Copper 85 - 90%
Uranium 90 - 95%
Gold 95 - 98%
Coal 85 - 90%
Aluminum 85 - 90%

Petroleum 30 - 40%

The low recovery of our petroleum resources probably stems from its abundance. Early on, when the magnitude of petroleum supply was unknown and its uses were minor, petroleum was mined. This effort was possibly one of man's earliest activities. We do know that the production of petroleum by mining parallel's man's history ever since 5000 B.C. The Egyptians used bitumen mined from surface exposures for use in embalming. The word "mummy" is derived from the Persian word for bitumen "mumiai". Moses bulrush cradle is described using the Hebrew word "sift" for pitch or bitumen as the substance that protected the infants craft as it floated on the Nile in about 1300 B.C. Herodotus, about 450 B.C., cited a place near Susa, Persia, where shallow shafts and short drifts were used to extract bitumen, salt and oil.

In time, with an increase in population and demand for bituminous materials, more elaborate methods were used to mine petroleum in Romania, France, Germany and other areas. Alphalt mined in Trinidad caulked ships and paved streets. Locally mined bitumen was produced in Alabama, Arkansas, California, Missouri Oklahoma and Utah as well as in a number of other states - all by mining. One of the earliest references to oil mining in the United States appears in the 1889 report of the geological survey of Ohio. It cites an 1865 effort near Markburg where a shaft was sunk and the oil that seeped in was recovered. In 1866 more than thirty drainage tunnels were driven into the oil sands of Sulphur Mountain near Ventura, California where oil production continued for many years. Similar activities took place else where through the country.

When Edwin L. Drake successfully drilled a hole near Titusville, Pennsylvania in 1959, he opened a new book on oil production. The speed and low cost of drilling oil wells resulted in the proliferation of well drilling techniques. Concurrently oil mining fell into decline. For over half a century oil mining was almost abandoned. More oil than was actually needed was produced at far less cost and with greater safety than by mining. To reduce the surplus, schemes were generated such as the almost free distribution of lamps to encourage oil use. To wit "oil for the lamps of China".

Petroleum production exceeded demand. It was not only abundant, but a very cheap fuel. As the automobile became commonplace, no one gave a thought to engines that would operate efficiently in terms of fuel use. More and more power was in vogue as the walking beams on pumps provided the liquid energy and the oil companies profited when selling oil for less than a dollar per barrel.

Oil mining, largely abandoned was successfully practiced at Pechelbronn in France, Wietze in Germany and at a few other locations, all in countries that were not petroleum rich. In 1923 H. Foster Bain, then Director of the U.S. Bureau of Mines, visited a number of petroleum miningsites and instructed that a staff study be made. George S. Rice, then Chief Mining Engineer of the Bureau conducted this study and the findings were published in 1932 as Bulletin 351 "Mining Petroleum by Underground Methods".

By 1932 well drilling for petroleum was a sophisticated techology and oil mining was a forgotten science. The Bureau of Mines Study included a number of conclusions, some of which remain valid more than fifty years later. He cited technical limitations to oil mining such as excessive gas, oil or water pressure. He set forth a tentative depth limit of 4000 feet by relating his conclusions to the depth at which European coal mines were then operating.

One interesting conclusion related to the appropriate economic climate for oil mining. Mr. Rice stated that one favorable condition for oil mining was "....that the price of crude oil at the top of the shaft is at least $2.25 per barrel." And that was when crude was selling for 10-15¢ per barrel (1931).

In his concluding paragraph Mr. Rice said "...in the interest of conservation of a great natural resource, every encouragement should be given to recovering part or all of the 60-80 per cent of the original oil content of the oil sands following escape of the entrained gas".

Not much has happened in oil mining since then. New oil fields continued to be discovered. Drilling techniques inproved and wells continued to skim off 30-40 percent of a fields total resources. Consumption of oil escalated by leaps and bounds. Many studies appeared predicting various run out dates. A study I made in 1956 while employed in coal mining concluded that domestic petroleum production would peak in 1970 and decline there after. Unfortunately that 1956 prediction was correct. Imports of petroleum began a rapid increase going from 4.74 million barrels per day to 8.81 million barrels per day in 1977, since declining to 5.04 million barrels per day in 1982 as the efforts to reduce oil consumption took effect.

At the same time more and more water flooding and other secondary recovery methods were applied in efforts to extract more oil from existing wells. Tertiary methods of modifying fluid properties to achieve a higher displacement efficiency were also applied.

In 1972 the Engineering & Mining Journal published Earl Herkenhoff's article "When Are We Going to Mine Oil?" Earl wrote his article in 1971 when oil was $2.50 per barrel. Then lightning struck with the petroleum embargo and OPEC.

It was apparent that there would be significant impacts as a result of these events. The Bureau of Mines published a report on the impact of 60¢, 80¢ and $1.00 per gallon gasoline on the demand for steel, copper, aluminum and other metals used in the manufacture of automobiles. Published under the title "Determining the Effects of Gasoline Price on the Use of Metals in Automobile Manufacture" the report was hardly noticed. However, the study showed that mineral requirements for U.S. automobiles would reduce by 15% with 60¢ gasoline and by 26 percent and 35 percent respectively for 80¢ and $1.00 per gallon gasoline. A quick examination of the U.S. steel, copper, lead, aluminum and zinc industries bears out the predicted impact of higher fuel costs.

The oil embargo led me to review the 1932 report by George S. Rice and I urged a restudy of petroleum mining in the light of the vastly altered economics. Two studies conducted under U.S. Bureau of Mines contracts, one by Golder Associates and another by Energy Development Consultants brought oil mining into sharp focus when published in 1978. Both reports developed concepts of value for decisions as to how to proceed for the mining of petroleum.

One of the more important results of these studies was the establishment of target size. This examination of the U.S. reserve/resource position showed that:

		Billion Barrels
1)	U.S. original land based oil resource	450
2)	Producible by conventional method	
	Primary 17% recovery	
	Secondary 17% recovery	
	Tertiary < 5% recovery	175
3)	Already produced	125
4)	Remaining resource amenable to primary	
	Secondary and Tertiary recovery	50
5)	Resource remaining after application	
	of conventional methods	275

Thus there is a target of 275 billion barrels of petroleum much of which may be amenable to a quarternary method - oil mining. Should we make a major effort to pursue the technologic-economic indications of fourth order recovery and make 25-30 percent of the 275 billion barrels available, the political-economic impacts world wide would be staggering and U.S. recoverable resources would be almost doubled.

There are witnesses here today who will treat with some depth the available technology and the details of production. In presenting this perspective of oil mining, it is intended to highlight the factors that impinge on the undertaking of oil mining on a large scale - that is with a multiplicity of projects.

If we are to get into oil mining in a substantial way, there is a need for a melding of the two engineering disciplines involved. Petroleum engineering technology must be merged with mining engineering technology for satisfactory solutions to the problems of oil mining.

In the conduct of these two oil mining studies the subject was examined from a number of different view points along with the technical, economic and environmental requirements and impacts. It became recognized that oil mining is a viable fourth order petroleum recovery mechanism that is completely different from the "conventional" generic techologies of primary, secondary (adding new energy to old reservoirs) and tertiary (modifying fluid properties to achieve a higher displacement efficiency).

Oil mining requires a technology that is without equal. Further, this fourth order or quarternary method of oil recovery has many unique characteristics.

1) Unlike the first three orders of petroleum recovery, the fourth order requires that mining engineering technology be applied together with petroleum technology . Neither mining nor petroleum engineers can work autonomously in this fourth order methodology. The joint efforts of both disciplines is essential to the successful accomplishment of oil mining.

2) Unlike primary, secondary and tertiary techiniques that are conducted from the surface with small diameter holes, quaternary methods require that people go underground except in those cases where the deposit is amenable to open pit mining.

3) Unlike the first three orders of recovery each of which recovers only fractional portions of the original oil-in-place (17%, 17%, < 5%) the fourth order will recover more of the oil-in-place than all other known technologies combined have recovered. Actually quaternary technology requires this high level of recovery in order to justify the large front end investment required.

4) Unlike primary, secondary and tertiary technologies that primarily, utilize existing natural energy to lift oil to the surface, oil mining requires either utilizing unapplied or ineffectively applied energy (gravity or capillary energy) or eliminating the energy (drive) question completely by extractive mining and processing.

It is the relentless pressure of economics combined with the diminishing reserves amenable to primary, secondary and tertiary methods that forces the application of oil mining. Conventional methods applied to reserves can no longer satisfy our petroleum needs and we should not accept the hazards of reliance upon uncertain and exorbitant foreign sources. We must take those measures that are essential to achieve a high degree of self-sufficiency.

Using the best available technology we must emulate Japan, France, Germany, Canada and Russia in applying oil mining to our resources in order to convert them to recoverable reserves.

Price exerts powerful leverage in setting the directions in which we must move. As George Rice observed in 1932, oil mining was unattractive when oil from wells as available at low cost. Now with prices on the order of $29 a barrel, the ± 60% of our original oil-in-place becomes a national asset of incredible value.

What does it take to make this reserve of mineable oil available? For the most part the resources are either the property of or under lease by existing oil companies. The oil remaining in the ground is most often the same plus 25 degree API oil that is the feed stock to present refineries. In most cases the collection and transportation installations that handled the product of the first three orders of recovery are still in place and operative.

The extensive application of oil mining does require innovative thinking on the part of industry and government. Although petroleum producible by oil mining is old oil geologically, it is new oil in the very real sense that it would never be produced but for the application of oil mining techniques. To tax oil produced by oil mining as old oil could, in many cases be a sufficient cost burden to preclude the availability of oil that might otherwise be produced. Thus tax treatment of mined oil as old oil couldwell be a destructive disincentive to national goals as set forth in our energy policy.

Except for a few isolated instances of oil mining, capital and operating cost data is based upon estimates. Although more current estimates exist for specific private industry projects being studied, the publically available data appears in the 1978 report by Energy Development Consultants. The then applicable economics of oil mining was based upon mining the oil in both a 100 foot and 200 foot thick reservoir. The projections were based upon a reservoir about 3000 feet deep and applied to a square mile of reservoir.

Capital costs were then estimated to range from $41,000,000 to $57,000,000 for a 100 foot thick reservoir and from $43,000,000 to $60,000,000 for a 200 foot thick reservoir.

Updating these capital costs to 1983 levels would raise the estimate to $50,000,000 to $70,000,000 for a 100 foot thick resorvoir and $55,000,000 to $75,000,000 for a 200 foot thick reservoir. This projection is based upon a 10 percent per year inflation rate.

For this scale of investment, we could expect initial production of about 14,000 bbl/day from a square mile of 100 foot thick reservoir and about 55,000 bbl/day from a square mile of 200 foot thick reservoir.

Over a projected 35 year life the 100 foot reservoir would produce an average of 1,575 bbl/day and the 200 foot thick reservoir would average 6,000 bbl/day.

The "front end" money required to provide a million barrels per day is substantial. At an estimated 20,000 bbl/day with a capital investment of $60,000,000, a million barrels per day of production would require fifty 20,000 bbl/day units and a capital investment of three billion dollars.

In 1978, production costs of $12.50-$15.25 per barrel were predicted for mined oil. It is more likely that costs today would be on the order of $20-$22 per barrel. Hopefully the testimony presented at this hearing will include more precise data. In any event the cost of quaternary production is considerably more than the combined production cost of the first three orders of production and may be five to seven times the average lifting cost of OPEC oil. At the same time quaternary oil production is expected to be substantially less than the cost of producing oil from shale. Synfuels cost would be even higher than the cost for oil from shale.

Oil mining would, when sufficient installations are operating, reduce the opportunity of foreign producers to jeopardize our economy and security. Oil mining would serve to lower inflation rates and unemployment and increase the Gross National Product. Without the ominous threat of taxation of mined oil at the high rates applying to old oil, we could look to more quaternary under takings by private industry.

For the time being, we seem to be getting by as regards oil supply. Should the energy crisis reoccur, the fallacy of too much dependence upon off shore sources will become painfully evident. The means to avoid a liquid energy crisis is within our hands.

Senator WARNER. Thank you, Mr. Wimpfen. That was a very helpful, historical perspective. I appreciate the technical judgments you provide from a background of extensive experience.

I might note for the record that Mr. Terrell with this subcommittee was once associated with you and has very high regards for your profession and viewpoints.

Before we proceed with this hearing, I must say that the Chair is highly intrigued with this subject. The thing that impresses me is that I have great faith in the free enterprise system of this country. As I sit here reflecting on the very modest amount of dollars that I possess, the question keeps recurring in my mind, why is this not being conducted by the major oil companies if it is technically and economically feasible?

There is little that they cannot do once they put their minds to it. I have been on this committee several years and listened to a lot of testimony in this hearing room. This is the problem that I have in my mind, so the balance of the witnesses can touch upon that. We will go to Dr. Fine now.

Mr. WIMPFEN. I can address that. My speculation is although I know some of the major oil companies are doing things, and maybe all of them are I do not know, they are not going to publicize what they are doing, because they can be whipsawed. The so-called seven sisters major oil companies rely heavily on imports from the OPEC nations.

Senator WARNER. I would like to hear from the rest of the witnesses and see what their views are.

Dr. Fine.

STATEMENT OF DR. DANIEL J. FINE, RESEARCH ASSOCIATE, MINING AND MINERALS, MASSACHUSETTS INSTITUTE OF TECHNOLOGY

Dr. FINE. It is a privilege to be here at this hearing, which I think is historic, because the hearing record certainly should be introduced in the next round of debate over the strategic petroleum reserve. Congress, of course, wants to increase the per day increasing of the reserve and here we have a reserve in the United States through oil mining, which is vast and commercially economical and almost by its very presence alleviates the need for the strategic petroleum reserve.

So I think this record is going to be historic and will begin to penetrate future debates around other alternative energy programs and policies.

First, I would like to reply very briefly to Senator Warner's perplexity. This hearing is an interesting exercise in that the majors, the oil companies in the United States are very well aware of this hearing, but several of them, if they are not sending—that they do not have observers here to take a look at this as a window in terms of what the industry is doing, they are nevertheless in many cases advising and designing oil mining units within the corporate structure.

I think it is no secret to name one, Pennzoil, which is very well positioned in the Appalachian area where most of the oil it is con-

sidering and has considered in the last 3 years such an oil mining unit to explore their first projects.

Another part of the free enterprise system is a firm which was commissioned by Mr. Wimpfen when he was chief mining engineer in the United States as energy development consultant, which dissolved in 1981 and became an operating company under the name of Tetra Systems. Tetra Systems is not here today, primarily because it is bound by a secrecy agreement with two of the majors in discussions now over the first large scale and very significant oil mining project in the United States, in Ohio, employing the method of gravity drainage.

Finally, Arco, which is of course believed and popularly conceived to be very well positioned now in Alaska and, two, with possible acquisition of Gulf is a primary major in this respect interested in oil mining and its application for Arco of being considered.

What will Arco do with the Alaska's reserves when pressure begins to fall, which is now predicted in the next 2 or 3 years? So oil mining is being actively explored and for various reasons and I think Mr. Wimpfen is correct, the tight hold aspect of information and what each is doing prevails here this morning and up to this time.

I would like to go through my testimony and highlight some points I made, and circle back for a moment to the concept of the strategic petroleum reserve.

First, I would like to mention the scale we are talking about and it needs to be emphasized. Oil mining in the United States will convert Texas and Louisiana into the Saudi Arabia, and Pennsylvania, West Virginia, Ohio, and Kentucky into the Persian Gulf Emirates of the next century, non-OPEC world. We are talking about 125 billion barrels of light oil, accessible to the gravity draining technique or technology under the general umbrella of oil mining, 125 billion in Texas and Louisiana and 50 billion in Pennsylvania, West Virginia, Ohio, and Kentucky in that order.

This magnitude of oil will realine the world's oil reserve picture and the implications in terms of energy, security, and world politics enormously. In fact, it is possible, I think, to say and I feel confident in saying that an application here of oil mining would return the United States to its pre-1970 nondependence position, energy nondependence as it was before 1970.

Even as we conduct this hearing in terms of the Iraq and Iran war, one major oil mining project on the scale that it is being discussed in Ohio would make the cutoff of Iranian oil in 1979, which was 850,000 barrels per day, as important to this economy as one deep freeze of Florida citrus in terms of dollars. So that there is a U.S. reserve, a potential for oil mining of eliminating or reducing the externalities, the serious disruption of oil supply and the inflation induced oil recessions, which in effect battered the U.S. economy and public for 12 years.

I do not want to use the word energy deplete dependence, but it comes very close when you look at an extension of the timeframe of 175 billion barrels of oil. This takes us through most or at least half of the next century in terms of domestic reserves and thus eliminates any outside interference or penetration of world energy markets, disruption of those markets, price escalations, and so on.

We are talking about the equivalent of 20 Alaskan northern slopes all suddenly discovered, actually not discovered, but as new or old oil, however it is designated, oil in the ground or left in the ground because conventional recovery technology is not sufficient to bring it up.

I would like to point out something else. There is extremely keen interest, internationally, in this. A conference has been planned in London for international oil mining, after having been postponed in 1981 and the participants in the conference and the requests for information are coming in from countries such as Brazil, Indonesia, and India, Mexico, Columbia, and Ecuador and these happen to be countries which have the properties, the reservoir properties for the application of oil mining through the gravity drainage method.

So once you add on the reserves that come into play from those six countries to the American reserves, you begin to get an oil reserve, world oil balance supply through reserve calculations which keeps oil and hydrocarbons in the energy picture toward the end of the 21st century and simply shatters the projections of several very prominent world energy studies which has us moving away from oil, the industrialized countries moving away from oil by the last part of this century.

It is critical to understand as Mr. Wimpfen pointed out, that we are talking about the 68 percent of the oil that remains in the ground and that oil, how to extract that oil becomes the design or the designated mission of oil mining. Oil mining, I think, from the prospective that I am presenting it, which is also the prospective of EDC and Tetra Systems, refers to a gravity drainage technology. In simple terms, gravity drainage consists of sinking shafts to beneath existing oil reservoirs. It uses raised bore drilling in an upward direction so the oil contained in the rock flows via gravity downward. The oil is then pumped to the surface.

Oil mining and gravity drainage is then the recovery technique that would add the 150 to the 175 billion barrels of oil to the United States. Several other methods which come under the umbrella of oil mining are not considered in this reserve figure.

Again, let me emphasize too that the oil mining reserve in the Eastern United States that we are talking about in terms of 50 billion barrels is light oil, environmentally acceptable and readily utilized within the existing transport system and in infrastructure.

Oil mining is cheaper than all other alternatives. It is cheaper than all synfuel alternatives. In fact, there would not be a synfuel program existing, I am certain, if this committee had received recommendations under the Carter administration following the commission study and recommendations from the Bureau of Mines in 1978 with the Department of Energy. Possibly this committee would then have supported oil mining with Government intervention or facilitated certain kinds of incentives that would have provided for an early project by at least 1980 and then we would have had one or two projects by 1984.

What is the cost? The latest cost assessment has one project in Ohio that is very close to moving operation, it is $14 to $18 per barrel cost. That brings it, $14 to $18 is far below the synfuel alternatives, shale, tar, sands and the coal gasification which is all around the $40 per barrel mark. So this and microbiology, by the

way, the use of microbiology and microtechnology and the biological calcalyst approach, oil mining in these two approaches remains as an economic alternative against the entire range of technology considered under the synfuel program and supported as such around the world.

According to the World Energy Conference study, of 1980 and published and discussed in 1981, the projection for oil drilling and exploration costs in the United States alone would be by 1990 $802 billion. And I pointed out in my testimony that that $802 billion would mean that the oil industry in the United States would have to go out and borrow $710 billion just for drilling and exploration costs.

Oil mining requires minimum, almost zero exploration and drilling costs. The costs are historic. They have been amortized over time. Thus the financial markets which are already pressed by Government borrowing and corporate needs would be relieved if the energy industry would not have to pick up, that is to go through the capital markets for net borrowing of $802 billion by 1990.

I think it is important in terms of the low cost of oil mining. There is no exploration cost. There is no drilling cost. If there is any cost, it is an operating cost in the new wells which are a different type and very marginal. This, of course, is astonishing in the sense that what we are talking about a very low cost energy solution against conventional mining operations or oil operations within the majors.

I would like to point out something else that has come to my attention to the chair. There is much controversy over the Santa Barbara Channel in California for off-shore oil concerning the leasing program and the environmental resistance of State off-shore environmental programs, the coastal program, for example. Oil mining as projected in the Santa Barbara Channel would be environmentally acceptable and since it is heavy oil would be at less cost than the conventional approach which is to inject steam into the heavy oil from platforms, which is the source of the potential hazard in environmental terms.

What the oil project would do in Santa Barbara, it would begin on-shore and tunnel out underneath the reservoir and then by the oil mining approach begin to drill upward underneath the off-shore oil and inject the steam into the oil and it would drain by gravity downward environmentally clean. This is an example of what would happen with a major application of oil mining.

Why has oil mining then not been exercised? I think it must be pointed out and the studies demonstrate Germany and Japan did it when they became acutely short of fuel. There is some surprise that this was not done in the last 10 years. I believe when you look at the history of oil and supply and demand, oil mining had to await the long domestic oil expansion to end and when faced with depletion and high cost of drilling and exploration, oil mining emerges now as the alternative.

The information and indications now coming from the industry is that resource management within the oil industry is without the externalities. It is without Government intervention for prices or public consciousness or political risk around the world. Industrial

management of majors and smaller independent companies are taking this on the basis as an approach within the prudence that it is an option that has come very close to within management projections of how to conduct business in oil in the next 50 years.

I would like to point out in conclusion that with oil mining arising in the United States, the instability that has been punctuated and has disturbed the basis of western European and Japanese relations with the Middle East and also the tremors that go through the market and are expressed in political terms every time there is a threat to the Persian Gulf or disruption to the flow of oil, all of this would subside with domestic oil mining alone in the United States.

The United States may not ever have total energy independence, but this would be a stretch out of nondependence. OPEC intervention would dissolve; lower prices at the pump. One could project a 25- to 30- percent decrease in the cost of oil at the pump. And, of course, the inability of OPEC to control their part of world production might then send prices even lower.

A foreign policy would emerge in the United States without considerations that one would consider preoccupation or deliberation with respect to what happens in the Persian Gulf. Strategic petroleum reserve oil itself and the expense and the cost of maintaining it could be retired from the Government budgets and the deficit budgets as well.

Finally, in conclusion, let me point out that given the potential of oil mining, there are just two notes of uncertainty that remain and those are only technical uncertainties. As the Ohio project goes forward, and it could very well be announced within this next summer or this summer, there is only, in terms of a formula for oil mining as gravity drainage in the project, I understand that only the rates of production remain unknown. And the barriers of resistance, resistance barriers to the approach within that particular reservoir are two unknown variables and they can only be known through the extension of the operational project, which is underway.

Senator WARNER. Would you repeat that?

Dr. FINE. The two are the rates of production according to the formula are unknown.

Senator WARNER. In other words, the rate is the speed in physically extracting this oil by virtue of gravity?

Dr. FINE. How much you have in your reservoirs is one side of the question, the estimation of oil in place.

Senator WARNER. But the rate is a function of how fast you can get it out?

Dr. FINE. Yes.

Senator WARNER. I suppose that the formula depends on the character of the soil that this particular well is in and the viscosity of the oil.

Dr. FINE. Correct, and this particular site has been selected very carefully to be the ideal site.

Senator WARNER. The one in Ohio?

Dr. FINE. The one in Ohio. As this goes towards the operational stage one, the only unknown, remember I think is, there is a formula. The operating company has the formula. That is unknown

technology and as they become emperical and analytical and follow the formula, they will discover that perhaps the formula and rate of production will be at variance and they can make adjustments to that.

The point here is there is no real uncertainty technically or technically binding within the oil industry that prevents oil mining from gravity drainage from occurring at this particular time.

Senator WARNER. We are getting into that area where the Chair is really trying to focus this hearing, the perspectives of this problem, the international ones and military ones. What we are trying to ascertain is why has not someone done this and what is the feasible practicalities engineering-wise?

We will put your statement in its entirety in the record.

[The prepared statement of Dr. Fine follows:]

OIL MINING: STRATEGIC AND MARKET IMPLICATIONS OF THE END OF ENERGY CRISES

Testimony before
The United States Senate
Subcommittee on Energy and Natural Resources
Washington, D.C.
March 2, 1984

by Daniel I. Fine
Research Associate
Mining and Minerals
Massachusetts Institute of Technology

Oil mining of the United States will transform Texas and Louisiana into the Saudi Arabia and Pennsylvania, West Virginia Ohio, amd Kentucky into the Persian Gulf Emirates of the next century, non-OPEC world. No less than 125 billion barrels of oil reserves would be added to existing Texas and Louisiana reserves through oil mining recovery. And Pennsylvania, West Virginia, Ohio, and Kentucky would possess 50 billion barrels of "new" oil reserves. The magnitude of this realignment of the world's oil reservers is so massive that it restores the United States to energy non-dependence, a state of affairs similar to the pre-energy crisis period which prevailed before the 1970s. But most significant is the prospect that with oil mining the current Iran-Iraq war, which in recent weeks has once again sent tremors of anticipation into the markets that an oil supply disruption was imminent would have less impact on the American economy than once deep freeze reaching the Florida citrus crop.

Oil mining extends the transition time to a post-hydrocarbon energy world far into the 21st century, as the equivalent of 20 Alaskan North Slopes/ Prudoe Bays are suddenly "discovered" in the United States alone. But the potential of oil mining is international. Reservoir characteristics are amenable to oil mining in Brazil, Indonesia, India, Mexico, Colombia, and Ecuador. Indeed, as oil field pressure inevitably falls on a universal basis, tertiary enhanced recovery (oil mining) could prolong production even in the Middle East. It is absolutely critical to recognize, therefore, that oil mining is designed to recover that oil which remains "in the ground" after conventional recovery technology is applied. And that oil "left

behind" amounts to 68% of the original reserve.

If there had been at least one major oil mining project in the United States, either before or after 1973, the shape of contemporary history would be scarcely recognizable. OPEC would no doubt have remained a producer association with somewhat more impact than that which meets on tantalum. Energy price escalation would not have caused both inflation and partially two worldwide recessions. International politics would have been relatively untouched by Irans and Lebanons. If the Congress has been presented with an oil mining alternative in the energy policy of the Carter Administration or before, this Committee might have had the opportunity, choosing between high-cost synfuels and low-cost oil mining, to have prevented the loss of 850,000 barrels per day from Iran in 1979 from having any impact on world politics and energy supply/demand. It was precisely in the summer of 1978 that the former Chief Mining Engineer of the United States received two studies from private sector consultants which he had commissioned earlier. Yet, his positive recommendations were "lost" in a bureaucracy of an Administration which pursued energy conservation in the same spirit as it evaded the prospect of new domestic oil production.

Oil mining, in the sense of this paper, refers to gravity drainage technology as developed by the Energy Development Consultants (authors of one of the Government studies) which has since become an operational company (Tetra Systems) for the purpose preparing the first oil mining project in the United States. Gravity drainage consists of sinking shafts beneath exiting oil reservoirs and employing raised bore drilling up-

ward so that the oil contained in the rock flows via gravity downward. That oil is then pumped to the surface. Oil mining/gravity drainage is the recovery technology that would add 175 billion barrels to the oil reserves of the United States. Moreover, this oil is light, environmentally acceptable, and will utilized existing investment in transportation and processing infrastructure.

Oil mining/gravity drainage is cheaper than all other synfuel alternatives. While tars, sands, shales, and coal gasification require energy prices around $40 per barrel, oil mining by this method is in the 14 to 18 dollar range. No Government incentives, such as, guaranteed loans or floor prices, are needed; oil mining is competitive on the current world energy market.

Based on the World Energy Conference Study, by 1990 the cumulative finance cost of exploration and drilling in the United States will add up to $802 billion. This equals four times the contentious Federal Budget for fiscal year 1985. It also means that the oil industry must borrow $710 billion from the same capital markets which are "squeezed" by government finance and non-energy corporate debt requirements. With oil mining, therefore, not only would the United States re-establish energy security but indirectly the oil industry share of new borrowing would be reduced to such an extent that needed capital can go elsewhere in the economy and the upward pressure on general interest rates would be sharply reversed. All this because oil mining/gravity drainage requires extremely small exploration and drilling finance. The drilling and exploration costs are historic; oil has been discovered and the expense of development amortized generations ago.

Oil mining brings down the cost of enhanced recovery. Such recovery has been high-cost because multiple wells with close density are needed to offset reservoir discontinuity. But oil/mining gravity drainage provides high density wells from underneath; therefore, tertiary applications are cheaper and more efficient. For example, oil mining/gravity drainage combined with surfactants will yield 80% recovery of the 68% oil "left in the ground."

Oil mining/gravity drainage has advantages over surface high-density drilled wells on environmental grounds. The Oklahoma City pool and that beneath Los Angeles exclude high-well density but oil mining from below is unlimited in the number of gravity-inclined upward drilled holes.

Far more important is the potential of oil mining/gravity drainage to some off-shore oil development. For example, environmental resistance in political terms to the Santa Barbara channel in California would vanish overnight with a gravity/drainage approach because of its central underground component. Steam injection underground eliminates the environmental risks of steam injection from platforms. Costs would be reduced via the underground approach, as heavy oil is involved.

Oil mining was first demonstrated in Japan and Germany during the Second World War when those countries became acutely short of fuel. It has awaited the long period of domestic oil expansion to end. With depletion and with the exception of Alaska and off-shore, oil mining emerges after after a half-century as the alternative to the oil industry. Energy shock was not sufficient to stimulate the typical crash-program that would have attracted public attention and launched oil mining a

decade earlier. Nevertheless, it is on a more durable basis that prudent oil resource management itself has arrived at the threshold of oil mining without the undue influence of the externalities.

Energy shock was not sufficient to stimulate the typical crash-program that would have attracted public attention and launched oil mining a decade or less earlier. For the last week the world has awaited the latest confirmation or disconfirmation of Iraq and Iran disruption of the flow of oil to markets. Against this instability in the very essence of industrial civilization, there is yet only a perceptual barrier between the United States and total energy independence, the dissolution of OPEC intervention, lower prices at the pump, and a foreign policy or national security deliberation without the relentless "moment of truth" burden of the Persian Gulf. The Strategic Petroleum Reserve need not have been invented.

STATEMENT OF MICHAEL J. HYLAND, ENGINEER, INTERNATIONAL ENERGY ASSOCIATES, LTD.

Mr. HYLAND. My name is Michael Hyland. I am an engineer with International Energy Associates Ltd. in Washington, D.C. I have had some recent involvement completed about a year ago with oil mining. I would like to tell you a little about that and answer any questions you may have in the area.

With regard to your question, Senator Warner, in addition to my printed testimony, let me say that your question is quite valid. Why has not anything happened? First of all, it has only been 10 years since the oil shock of 1973, pushing price up. Traditionally the petroleum engineers and mining engineers do not work in the same companies. Even in a large oil company, they often work in totally different parts of the company.

So unless positive action is taken to put an interdisciplinary team together, the ability to trade off costs in the oil side and the petroleum drilling—in the oil mining side and the petroleum side, they are often not done properly or done at all, so that an economic situation is not found.

I have the pleasure of directing a group of about six petroleum and mining engineers in an extensive study, which I will come to in the text. With regard to why nothing has happened, prior to Mr. Burlingame's testimony that they are going to do something, my attitude was that the private market place was not funding these projects for two reasons. Despite the fact that they might look economic, there are unknowns, as Dr. Fine has said. The drainage rates, no matter how good your petroleum calculations are, you just do not know what the drainage rates are—for sure—going to be until you go in and put some holes in.

Second, we do believe these mines can be done safely and we do believe that nobody will get hurt. But they have not been done yet. MSHA has spent time with me and my associates—MSHA being Mine Safety and Health Administration—and we do believe they are safe undertakings but they have not been done. So there is an unknown. There is an unproven operation.

I would like to go back to the printed text at this time.

Senator WARNER. Another thing keeps coming back in my mind. Several years ago when I first came on this committee, I spent a great deal of time on the subject of oil shale. I went and examined every one of the sites, down into the shafts, etc. At that time, of course, the petroleum prices were considerably higher, but my point is the scale, the magnitude of capital investment that went into oil shale and the brains that are brought to bear on how you get these enormous shafts down and cooking, why was not that same dramatic force suddenly focused in on this subject? Why did not somebody get a very small oil field and put up a prototype and give it a try?

Mr. HYLAND. I can say, sir, that all of the acts and all of the Government laws have directed—for example, the Energy Security Act of 1980 excludes or addresses heavy oil that is not otherwise economically producible. Therefore, it excludes this type of undertaking.

Senator WARNER. Would Congress deliberately pass laws to try and discourage this type of mining?

Mr. HYLAND. I can tell you my involvement started in about 1979 and I was active in the business and until a client walked in the door and said would you look at this for us, I had not even thought about it. Subsequent to that time, a team was assembled and we did about 6 or 7 months' work.

Senator WARNER. Is there a legislative program that you would propose? I am speaking collectively to the witnesses. I am tremendously interested. Is there a legislative problem there?

Mr. HYLAND. I am prepared to speak about my experience. I did not come prepared to make a proposal, sir.

Senator WARNER. I am just asking the questions that keep coming to mind. But you go ahead.

Mr. HYLAND. First, with regard to oil mining, I would like to refer that oil mining is basically, in my terminology, the drainage of oil from otherwise depleted oil reservoirs. I am not including tar sands or oil shale projects which have sometimes generically been called oil mining because they use mining to extract solids which are then processed for the recovery of oil.

The logic behind oil gravity drainage is quite simple. When oil is produced using conventional techniques, a great deal of the oil is left behind. That is when the pressures that pushed the oil to the surface have declined, a great deal of the oil originally in place is still left in the formation. The oil left in place would normally be 60 or 70 percent or sometimes as high as 90 percent of the oil originally in place.

The amount of oil left would depend on the geological characteristics of the formation, in particular its tightness or resistance to flow.

While these formations are depleted from the standpoint of conventional production, they are not totally dead. Usually some amount of gas pressure will remain in the reservoir and gravity will cause some flow of oil in the reservoir. This gravity is very much like the effect you would get if you were to punch a hole in the bottom of a can of water.

Technically speaking, we could drill a very dense pattern of holes from the surface, allow the oil to flow to the wells and then pump it to the surface. This would permit recovery of a large part of the otherwise remaining oil. In fact, in the early stages of becoming depleted, just such stripper wells were employed.

As the field becomes further depleted, we could technically continue production by continuing to drill dense patterns of holes in the field. However, the economics of such low production wells would normally be very prohibitive and as I said therefore from 60 to 90 percent of the original oil remains in the formation.

My statements concerning oil remaining will not be changed even if improvements are made in secondary and tertiary recovery. There will still be a substantial amount of oil left.

The reservoirs which are the best candidates for oil mining are generally older and relatively shallow reservoirs which have produced oil conventionally for some time. I do recall that candidate fields exist in a number of States. The gentleman before mentioned

the Golder report which lists, I do believe, Texas, California, Louisiana, about a dozen States with candidate fields.

The basic approach in gravity drainage is to get down close to the formation using mining techniques and then to drill a large number of short, cheap drainage holes or wells into the formation. Drilling these holes so close together from the surface would not be economic. Drilled from a location either directly under or perhaps right over the formation would make the holes quite cheap or cheap enough so the overall undertaking can be economic in certain formations.

The approach with which I am familiar, conventional mining techniques, would be used to sink or blind drill a shaft to just below the oil-bearing formation. Tunnels or what are commonly called drifts in mining jargon would then be developed under the formation. From various drilling chambers in these tunnels, wells would be drilled upward into the formation and the wells would be piped into a closed collection system. The oil draining from the numerous holes would then be pumped collectively to the surface.

Mining personnel would be underground during the development of the shaft and tunnels. A reduced number of personnel would be needed for the drilling of the wells. During normal oil production only inspection and maintenance personnel would need to be underground and then only on an intermittent basis.

My involvement with oil mining. On behalf of a private client, I directed a team of approximately six engineers and geologists on an indepth evaluation of a proposed gravity drainage oil mining project. The overall effort took about 7 months and we had a substantial effort carried out during this time. This undertaking looked at a single location and a single project. However, some of the things learned can be generalized to other potential oil mining projects.

The project appeared to us to be both economically attractive and technically feasible. However, at the time we completed the study, the price of oil was already falling. Although the project would still be economical at reduced oil prices, the marketplace perception of a flat or declining oil price, together with the technical uncertainties in the project, which I will come to in just a minute, made it impossible for the client to raise capital for this project in the current marketplace.

I have had limited contact with this client during the past year, but I did call him last week to tell him I would be giving this testimony. But apparently the project is still on the back burner.

The report we turned out was quite extensive and was the best that could be done without feedback data from an actually constructed project. The report itself contained about 200 pages summarizing the design efforts. It included conceptual design, geological and petroleum engineering investigations, the results of field coring work, cost estimates including quotes from firms who would bid for the construction, analysis of the overall project economics and an analysis of the environmental aspects including the results of meetings with the Mine Safety and Health Administration. In short, except for the tax and legal aspects, everything was included that could be done to evaluate this project prior to proceeding.

While I am not free to give you actual data from the report, I can say that we are speaking of a project of under $25 million total cost which would produce several million barrels of oil over the first 2 or 3 years of operation. Any more specific information on economics could be provided by the client, whose name is in my published testimony.

The technical uncertainties I mentioned cannot be eliminated before such a project is actually done. There are really two of importance: the actual safety situation which will be experienced and the actual field drainage rates which will be obtained from the numerous production holes.

Our conclusion from this design analysis was that such a project could be carried out safely. We had several meetings to review the design with MSHA and had on the project team a nationally known expert on ventilation from gassy mines.

The production rate calculations were carried out by a Ph.D. petroleum engineer who had extensive experience in production rate estimates from conventional wells. We had carried out field coring and permeability studies in the laboratory to permit the best possible calculated estimates. However, until actual production rates are experienced there is still an uncertainty.

I should say at this time there is a single project in—at least one project in operation, the Conoco mine in Wyoming. However, because of its configuration it did not provide field data for mines similar to what we needed. It was a totally different operation.

Let me summarize the situation as I see it. First of all, a good deal of oil can be recovered by gravity drainage, as much as we produce to date.

The technology is largely conventionally available. Any new technology is a very modest extrapolation.

The economics, at least for the case I am familiar with, appear attractive. I am sure that other potential projects would also appear attractive if subjected to the same degree of analysis.

The private marketplace, to my knowledge, will not currently undertake such projects because of the possibility of declining oil prices and the modest technical uncertainties that exist.

To my knowledge, no current Government programs are directed at gravity drainage for oil.

Thank you very much.

[The prepared statement of Mr. Hyland follows:]

TESTIMONY OF MICHAEL J. HYLAND
HEARING ON ENERGY AND MINERAL RESOURCES
MARCH 2, 1984

(Prepared February 27, 1984)

Gentlemen,

I am pleased to be with you today. I am an engineer with International Energy Associates Limited in Washington. In the past I have had some involvement with oil mining. I would like to tell you a little about that involvement, what I learned from it and answer questions if you should have any.

Firstly, I'd like to make clear what I mean by "Oil Mining". What I mean is the drainage of oil from otherwise depleted oil fields. I am not including tar sands or shale oil projects which have sometimes generically been called "Oil Mining" because they use mining to extract solids which are then processed for the recovery of oil.

THE LOGIC BEHIND GRAVITY DRAINAGE OIL MINING

When oil is produced using conventional techniques, a great deal of the oil is left behind. That is, when the pressures that pushed the oil to the surface have declined, a great deal of the oil originally inplace is still left in the formation. The oil left in place would normally be 60 or 70% and in some cases as high as 90% of the original oil in place. The amount of oil left would depend on the geological characteristics of the formation in particular its "tightness" or resistence to flow.

While these formations are "depleted" from the standpoint of conventional production they are not totally dead. Usually some small amount of gas pressure will remain in the reservoir and gravity will cause some small flow of oil in the reservoir. This gravity effect is very much like the flow you would obtain if you were to punch a hole in the bottom of a can of water. Technically speaking we could drill a very dense pattern of holes from the surface, allow the oil to flow to the wells and then pump it to the surface. This would permit recovery of a large part of the remaining oil. In fact, in the early stages of becoming depleted, just such stripper wells are employed. These are characterized by the "walking beam" pumps you can see operating in some of the older oil fields in U.S. today. These might produce something in the range of 5 or 10 barrels a day of oil.

As the field becomes further depleted, we could technically continue production by drilling such stripper wells on a much tighter pattern, allowing gravity and the now reduced gas pressure to produce perhaps one or two barrels a day for each well. However, the economics of such low production surface wells would normally be prohibitive and as I said before from 60 to 90% of the orginal oil remains left in the formation.

My statements concerning oil remaining will not be changed substantially even if tertiary recovery techniques become commercial. Techniques such as carbon dioxide or polyomer flooding will improve the amount of oil recovered conventionally but there will be still substantial quantities remaining for recovery by gravity drainage. In addition these tertiary techniques do not work on all reservoirs.

WHERE ARE THE CANDIDATE RESERVOIRS?

The reservoirs which are the best candidates for oil mining are generally older and relatively shallow reservoirs which have

produced oil conventionally for some time. I do recall that candidate fields exist in a number of States. If you'd like I can submit a list of these States which is from a publically available report.

DESCRIPTION OF GRAVITY DRAINAGE

The basic approach in gravity drainage oil mining is to get down close to the formation using mining techniques and then to drill a large number of short, cheap drainage holes or wells into the formation. Drilling these holes so close together from the surface would be uneconomic. Drilled from a location either directly under or perhaps right over the formation, the holes are cheap enough so that the overall undertaking can be economic in certain formations.

In the approach with which I am familiar, conventional mining techniques would be used to sink or blind drill a shaft to just below the oil bearing formation. Tunnels or what are commonly called "drifts" in mining jargon would then be developed under the formation. From various drilling chambers in these tunnels, wells would be drilled upward into the formation. The wells would be piped into a closed collection system and the oil draining from the numerous wells or drain holes then would be pumped to the surface.

Mining personnel would be underground during the development of the shaft and tunnels. A reduced number of personnel would be needed for the drilling of the wells. During normal oil production operations, only inspection and maintenance personnel would need to be underground and then only on an intermittent basis.

MY INVOLVEMENT WITH OIL MINING

On behalf of a private client I directed a team of approximately 6 engineers and geologists in an in-depth evaluation of a proposed Gravity Drainage Oil Mining project. The overall effort took about 7 months and while the team members were not on this one project full time during that period, we did have a substantial effort. While this effort was on a single location and project, some of the things learned can be generalized to other oil mining projects.

The project appeared to us to be both economically attractive and technically feasible. However, at the time we completed the study, the price of oil was already falling. Although the project would still be economical at reduced oil prices, the market place perception of a flat or declining oil price together with the technical uncertainties in the project (which I'll come to in just a minute) made it impossible for the client to raise capital for this project at this time. I have only had limited contact with this client during the past year but I did call him last week to tell him I will be giving this testimony. Apparently the project is still on the back burner.

The report we turned out was quite extensive and was the best that could be done without feed-back data from an actually constructed project. The report itself contained about 200 pages summarizing the design efforts. It included conceptual design, geological and petroleum engineering investigations, the results of field coring work, cost estimates including feed-back from firms who would bid for the construction, analysis of the overall project economics and an analysis of the environmental aspects including results of meetings with the Mine Safety and Health Administration (MSHA). In short, except for the tax and legal aspects, everything that could be done to evaluate this project prior to proceeding.

While I am not free to give you actual data from the report, I can say that we are speaking of a project of under $25 million total cost which would produce several million barrels of oil over the first two or three years of operation. Any more specific economics then that would have to be provided by the client, Mr. Joseph Rodano, of Petrol Inc. of New York City and Shreveport.

The technical uncertainties I mentioned cannot be eliminated before such a project is actually done. There are really two of importance: the actual safety situation which will be experienced and the actual field drainage rates which will be obtained from the numerous production holes.

Our conclusion from this design analysis was that such a project could be carried out safely. We had several meetings to review the design with MSHA and had on the project team a nationally known expert on ventilation from gasy mines, Floyd Bossard.

The production rate calculations were carried out by a Ph.D. Petroleum Engineer who had extensive experience in production rate estimates from conventional wells. We had carried out field coring and permeability studies in the laboratory to permit the best possible calculated estimates. However, until actual production rates are experienced there is still an uncertainty.

I will be happy at the end of my testimony to answer any question on these uncertainties. I should say at this point that the operating Conoco Gravity Drainage Oil Mining project in Wyoming could not provide actual field data back-up. It has a substantially different configuration since it involves a thinner, much more permeable oil bearing formation. Hence the required density of their drain holes and need for tunnelling under the formation is different.

WHAT IS NEEDED

Let me try to summarize the situation as I see it:

1. A good deal of oil can be recovered by Gravity Drainage Oil Mining.

2. The technology is largely conventionally available. Any new technology is a modest extrapolation.

3. The economics at least for the case I am familiar with, appear attractive. I'm sure that other potential projects would also appear attractive if subjected to the same degree of analysis.

4. The private market place will not currently undertake such projects because of the possibility of declining oil prices and the modest technical uncertainties that exist.

5. To my knowledge, no current government programs are directed at Gravity Drainage Oil Mining.

Thank you for your time Gentlemen. I would be pleased to answer any questions that I can.

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Is Oil Mining Becoming Attractive?

by W. P. Spence, *Mining Engineer*, and M. J. Hyland, *Vice President*,
Keplinger and Associates Inc., Houston, Tex.

The concept of oil mining may seem radical, but oil has been mined successfully in Europe as far back as the 1700s and in the U.S. in the 1800s. Activity has commenced once again in this area as a result of the world's search for additional energy sources. We will discuss one form of oil mining in this article, gravity drainage.

Oil mining through gravity drainage has long been technically feasible, but restricted by economics. However, with the Arab oil embargo and the resulting escalation in oil prices the economics now appear attractive.

Although we refer to the extraction process as oil mining, the techniques employed in gravity drainage would classify it more in line with a basic oil and gas operation. Mining only takes place during the design and developmental phases of the operation. Therefore, although mining is critical in the overall scheme, there is no mining per se in the production phase.

There is a significant relationship between reservoir engineering and mining engineering in oil mining. Mining engineering is contingent upon the field characteristics established by the reservoir engineers.

Gravity Drainage

So what is oil mining? There are two major categories of oil mining. The first is actual mining of host rock material and associate waste. This is the most common form of oil mining in practice today, as it is employed for the Colorado oil shales and the Canadian tar sands. The second major oil mining technique is gravity drainage.

A typical gravity drainage operation (Fig. 2) includes a mine shaft or an adit, which provides access for men, materials, and air. A chamber or a series of drifts (tunnels) then are excavated in or below the reservoir. Drilling activity takes place from these chambers.

Drain holes are drilled horizontally or vertically in a dense pattern into the reservoir. The drain holes are partially cased and completed. Flow is controlled by a series of valves and gauges typically employed on normal oil and gas wells. The wells are completed in a conventional manner, although they are upside down.

To avoid introducing hydrocarbons into the mine environment, oil will be collected in a closed system of pipes leading to a main collection sump from which the oil can be pumped to the surface. Once the tunnels have been excavated it is economical to drill the wells or drainholes at dense spacing.

While it is technically possible to drill a dense pattern of wells from the surface, the oil production rate per well with gravity drive would not be large enough to justify the expense, especially since each well's produc-

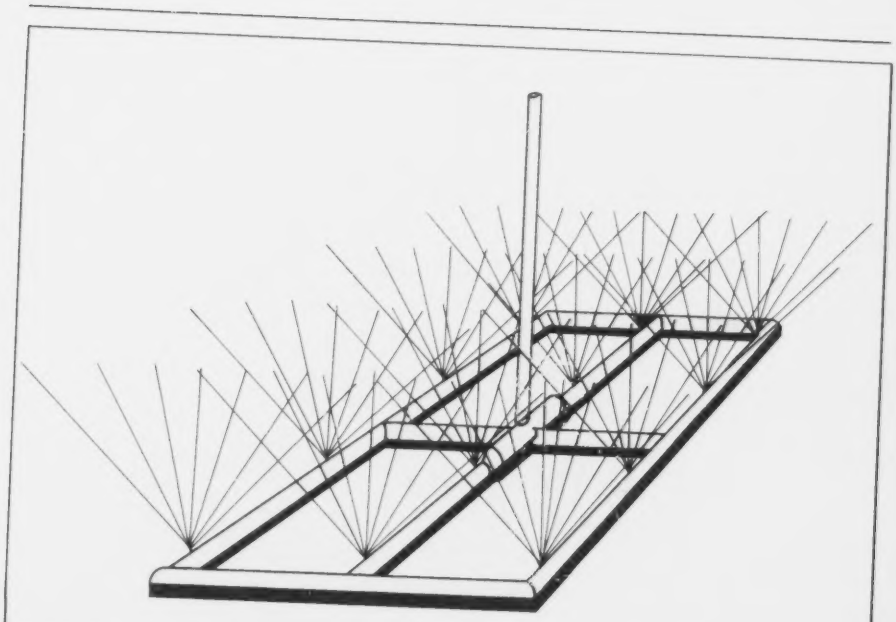

Fig. 1. General layout of a gravity drainage mine.

tion must be pumped separately to the surface.

Reservoirs depleted by conventional extraction methods still have a physical head just as a column of water exerts pressure. This physical head is the drive mechanism behind the oil, forcing it to the drainholes for recovery. The magnitude of this physical head as a driving mechanism will be substantially less than the water or gas driving mechanism found in conventional oil wells. Thus, close spacing of the holes becomes necessary.

Thickness of the pay zone and the formation's permeability will affect the amount of physical head available in the reservoir and determine the required drainhole spacing. In general, for a low-permeability, thick reservoir, 50-ft well spacing is typical. Each well or drainhole will be a low-volume producer. However, large production rates are attributed to the density of holes.

Reservoir Characteristics

It is estimated that 300 billion bbl of oil will remain in place in the U.S. once conventional extraction methods have been exhausted. About 50% to 60% of this oil can be recovered using some form of oil mining.

Several reservoir characteristics are necessary for a gravity drainage project. First, sufficient oil must remain in the field or lease. Large volumes of oil remaining in place could result from a high original volume of oil in place or a low percentage recovery through conventional extraction methods.

There is no set volume of oil necessary to justify a gravity drainage project. The amount needed will vary based on reservoir characteristics. As an example, a tight formation may require something in the range of 100,000 bbl/acre. This amount decreases for more permeable fields because each well or drainhole influences a substantially larger radius of drainage within the field. This necessitates fewer drainholes per acre and a reduction in the amount of required underground development.

The mining analysis should include a study of the formation's rock mechanics, such as rock type, compressive strengths, porosities, and permeabilities.

Another important characteristic is that the reservoir be relatively thick. This of course influences the amount of oil in place. More importantly, it influences the degree of physical head for the oil.

Directly related to this, any continuous layers of impervious material, such as shale, which may be present on the formation will reduce the physical head of oil and thus reduce the reservoir's drive mechanism. These impervious layers may not have been a factor during conventional production of the field since flow in the traditional case would be more or less horizontal to the borehole.

Two other field characteristics of importance relate to water. It is important the water content of the field be reasonable (maximum 4 or 5 bbl of water per barrel

of oil). Groundwater influx due to the presence of aquifers, for example, is an important consideration and must be interrelated to development and operation.

The fields most suitable for gravity drainage are relatively shallow — under 5,000 ft for initial gravity drainage projects. Beyond this depth two factors come into play:

- Shaft installation becomes substantially more difficult and costly.
- The temperature gradient in the earth makes operations difficult at extreme depths.

General Mine Configuration

All of the necessary mine development can be completed using standard equipment and practices. No new technology would have to be developed.

The drainholes would be drilled with a coal drill that has been slightly modified to include some standard oil field components.

Security Exchange Commission

An interesting nontechnical factor comes into play here. At what point would other reserves which are economically producible through gravity drainage be suitable for inclusion as company reserves in SEC documents? We are seeing a changing picture regarding new energy forms such as gravity drainage and coal bed methane extraction. As time progresses, we hope to see some changes in reserves classifications.

A pc itive aspect of oil mining is the attitude among regulatory organizations. The Mine Safety and Health Administration (MSHA) has been extremely positive toward getting this new industry into operation. Although there will be variance from site to site it appears that gravity drainage mines may be classified as nongassy, depending on the conditions.

State tax agencies such as the Texas Railroad Commission or the Louisiana Conservation Division will also have an interest in oil mining since they are responsible for oil and gas production. Their involvement would be in the area of production guidelines, reporting, and taxation.

The EPA and state environmental regulatory authorities also will be looking at oil mining projects. The environmental effects of a gravity drainage project would be similar to those of a conventional oil production operation with one exception — solid waste from the shaft and tunnel system must be removed and disposed of. Fortunately, the amount of material removed is not significant and if reclamation and reseeding of the solid material pile is carried out, oil mining projects should not experience many difficulties with environmental regulatory agencies.

In addition to solid waste disposal, the water and gas produced along with the oil must be disposed of. Water can be disposed of in water injection wells, while gas can be recovered as a product or flared. If flaring is to be carried out, a suitable system would have to be established to meet environmental requirements.

Experience proves the economics of gravity drainage projects applied under suitable conditions are extremely good. The economics vary substantially from field to field, however, so it would be inappropriate to generalize. Nevertheless, it appears that in many fields gravity drainage projects would be economical.

An important aspect relating to this is the fact that these are not "wildcat" operations. Technical risk is low. Conventional equipment and techniques would be used for the most part. Results are far more predictable, since we know the oil is there from field production data. We can define the field characteristics and calculate the expected production.

There are some uncertainties, however — it is not until a particular formation is drilled for gravity drainage that actual production parameters can be known with certainty. In fact, it is desirable to carry out a gravity drainage project in several stages. Initially, a shaft is installed and test wells drilled from a designated work chamber located at the shaft bottom. Based on production data from these wells, drainhole spacing can then be appropriately adjusted. In addition, any possible variations in the mine design could be implemented.

We are optimistic about the relatively near term development of this old but new oil source. We know the oil reserves are present. High prices for oil today can justify gravity drainage as part of a company's proven reserves, and development should be near term as no new equipment or technology is required.

About the Authors

William B. Spence joined Keplinger and Associates Inc. in 1981 as a mining engineer in Alternate Energy, Mineral, and Environmental Programs. Previously, he worked for Dr. Otto Gold Consulting Engineers of Koeln, West Germany, and established a U.S. office for the company, and for Mobil Oil Corp./Coal Producing Division in Denver, Colo. Spence received a BS in mining engineering from West Virginia University in 1979. He is a member of the American Institute of Mining Engineers.

Michael J. Hyland is vice president of Alternate Energy, Mineral, and Environmental Programs for Keplinger and Associates Inc., a post he has held since 1981. He was awarded a BS in chemical engineering from Manhattan College in 1961 and an MS in chemical and nuclear engineering from Columbia University in 1962. He also completed chemical engineering doctorate course work at New York University and earned an MBA from the University of Alabama. Before joining Keplinger, Hyland worked for Booz, Allen and Hamilton Inc. and Brown and Root Inc. in Houston, and in various other engineering capacities for several firms. He is a member of the American Institute of Chemical Engineers and is a Licensed Professional Engineer.

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Senator WARNER. I was asking counsel for the committee about the participation of the Department of Energy. Would you repeat what you said?

Mr. TERRELL. I understand the Department of Energy has prepared a report on mining of heavy oil and I understand that Stone & Webster Engineering Corp. was the contractor.

Mr. HYLAND. Yes, I do think out of Bartlesville they have prepared it and I do believe out of Bartlesville they have begun a modest study on light oil mining. I do believe, but——

Mr. SPENCE. They have.

Mr. TERRELL. That report has been requested for our record.

Senator WARNER. Thank you.

Dr. Trent.

STATEMENT OF DR. ROBERT H. TRENT, PRESIDENT, NEW TECH OIL CO.; ACCOMPANIED BY SASHA COBB, NEW TECH OIL CO.

Dr. TRENT. To begin with, I am Robert Trent, president of New Tech Oil Co. With me is an associate, Sasha Cobb, who is a graduate mining engineer of Colorado School of Mines. My education and expertise are in the field of mining, engineering, and mineral economics.

Senator WARNER. We have got all of that in writing.

Dr. TRENT. Good. New Tech is a closely held private company, organized in 1981 by myself and two others. During 1982 and 1983 without the aid of Government grants, subsidies or guaranteed price supports, we conducted a research and development project near Malta, Ohio and an underground facility. We sank a vertical shaft through the reservoir, tunneled underneath, drilled, over 14,000 foot of drilling and over 100 holes.

Senator WARNER. This project is separate from the one that has been mentioned in the testimony?

Dr. TRENT. Yes, it is different from that one, right. Based on our findings and data from this project, we are starting another project in a Western State, approximately April 1.

Senator WARNER. What were the economics of project No. 1?

Dr. TRENT. I prefer not to discuss it. That is proprietary at this time. If you would like to discuss it privately, I would be happy to.

Senator WARNER. I do not want to.

Dr. TRENT. We have a strong belief that mining technology and oil technology will ultimately result in the recovery of greater oil reserves. However, one thing that we have found, since we are satisfied with our technology that we can do it, is the fact that in today's society there are great inhibitions to technological advancements stemming from the Government regulations and rigid structures that cannot be done according to the established norms.

I agree with Dr. Fine that many problems exist with the Windfall Profit Tax Act. When the legislation was drafted, no one on the drafting process apparently was aware of the growing interest in gravity drainage technology. As a result, neither definition nor mention of oil mining was made in the Windfall Profit Tax Act. These facts became very evident to us in our economic research and to our astonishment, it was determined after repetitive legal

investigations that oil produced by mining is subject to the highest rate of windfall profit taxation.

Senator WARNER. That was done not by design but by accident?

Dr. TRENT. Strictly by oversight.

Senator WARNER. Are you suggesting—and frankly I did not go back and review that code prior to the hearing—are you suggesting that there is an area that Congress should examine in that tax structure to provide an inducement for starts on this type of recovery of petroleum?

Dr. TRENT. I will defer to Ms. Cobb.

Ms. COBB. Absolutely. The way the act is written now, the mined oil does not fall into any particular category.

Senator WARNER. The categories giving incentives for——

Ms. COBB. Exactly. For example, tertiary recovery has incentives. They have 30-percent rate under the Windfall Profit Tax. Mined oil does not fall into the tertiary unless you start using the objectives and that sort of thing.

Senator WARNER. It is a very simple thing to correct, I assume.

Ms. COBB. We have had some difficulty. We have been talking to Senators and Representatives on Ways and Means and the Finance Committee and we have come up with a tremendous difficulty in trying to get anything attached to the Windfall Profit Tax and have some sort of an amendment that would cover mined oil.

Senator WARNER. I intend to look into it. I will look into it, but I do not mean to criticize the Finance Committee, but somebody will be able to isolate for me that here is the language we need and the disposition of the various committee structures in the Senate.

Ms. COBB. We would be very happy to help in any way we can.

Senator WARNER. You can outline the problem.

Ms. COBB. Absolutely.

Senator WARNER. Could you do it a little bit now without violating confidence?

Ms. COBB. What we really need is a definition of mined oil and how it falls into the Windfall Profit Tax Act.

Senator WARNER. Or put an amendment on to include mined oil. Is that what you need?

Ms. COBB. That would be one vehicle, certainly. The problem right now is that independent producers, oil miners are trying to take properties that are abandoned from major companies or trying to buy a property that is marginal to a major and try to mine it. Because of the transfer limitations in the Windfall Profit Tax Act, the independent producer is up to a 60- or 70-percent tax rate, so if we could get out of that transfer limitation for mined oil.

The other problem is that mined oil from each of those wells is going to produce a million barrels per day, each hole is. So that classifies it as a stripper. But, again, there are transfer limitations in the Windfall Profit Tax Act that do not allow us to become classified as stripper, the same problem I mentioned with tertiary.

Senator WARNER. Speaking from a very limited base of knowledge on this subject, it seems to me, mining of oil, assuming it can be defined, should be put on a par with other means of recovery in terms of tax. That is my judgment. I will look at the mechanisms for which this can be done.

Ms. COBB. Just a definition of mined oil would be very helpful, not only with the tax aspect, but everything else, because the State laws have all of the spacing limitations, the spacing of wells. So there are problems there, not accounted for mined oil. Also the leases, there are certain restrictions on leased acreage that an oil mining project would take into account a lot of acreage, so there are limitations in that respect.

So, just a general definition of mined oil and what it is all about would be very helpful, cutting across all different kinds of legislation. I do not know how to do that.

Senator WARNER. I do not suggest I know how to do it either.

Dr. TRENT. I would point out also that the State of Ohio, there is currently legislation being drafted to allow mined oil a 5-year relief from State severance tax to see if it works, to see if we do have a problem.

Senator WARNER. They have not legislatively defined mined oil as of yet.

Dr. TRENT. That is in the process with the proposed legislation.

Senator WARNER. Is the Ohio Legislature in session now working on this problem?

Dr. TRENT. Yes, Senator Brandsfield. Ohio was very helpful when we acquired our permits to get away from the minimum spacing per acre. We had the equivalent of approximately 15 to 20 holes per acre rather than 1 hole as required by law.

Environmentally——

Senator WARNER. Well, this is beyond the scope of this hearing. We will have to tackle the problem.

Dr. TRENT. Getting back, our basic problem is that oil mining, we see it as being the alternative method of recovering oil in the fourth phase. It is applicable to properties in most cases that are no longer commercially produced.

Tentative reservoirs, we have identified tentative reservoirs throughout the United States, almost every State that has production.

We already addressed the transfer limitations.

Also, I would like to address as to why the major oil companies have not, they are studying it, but why they have not actually had a profit.

Ms. COBB. My feeling is that usually when you have a great idea, usually you see an independent entrepreneur going with it and running with the ball. Most of the major oil companies started because of an individual having enough initiative and drive to do it, and I think that is what you are seeing here in oil mining. You have a great idea. Mr. Wimpfen has been talking about this idea for years, but you really need an individual entrepreneur to run with it before the major companies will even take note. Even though I see that they are taking note with certain of their projects.

Senator WARNER. This is a mystery to me. I tell you that the independent oil producers are among the most enterprising people I have ever known in my life. We will get to the bottom of this.

[The prepared statement of Dr. Trent follows:]

Testimony
before the
Committee on Energy and Natural Resources
Subcommittee on Energy and Mineral Resources

by

Robert H. Trent, PhD.

March 2, 1984

My name is Dr. Robert Trent. I am president of New Tech Oil Company.

My education and expertise are in the field of mining engineering and mineral economics. I am a registered professional mining engineer in the states of Pennsylvania, West Virginia, Ohio, Colorado, Montana, Utah and Wyoming. I am currently filling temporary assignments in the capacities of Director of Mining and Energy Resources and Director of Research, BCR National Laboratory at the School of Engineering at the University of Pittsburgh.

New Tech Oil Company is a closely held private company that I and two other engineers organized in 1981 for the purpose of conducting research into the technology and economics of recovering oil by oil mining or, more specifically, by gravity drainage techniques. During 1982 and 1983 without the aid of government grants, subsidies or guaranteed price supports we conducted research at underground facilities within the Buck Run oil field near Malta, Ohio. The findings of our work has encouraged us to conduct a pilot plant study at a western state location.

I am of the strong belief that the cross fertilization of mining technology with oil technology can ultimately result in much greater recovery of oil from existing oil reservoirs than is possible with existing tertiary methods of recovery.

I have found, however, that in today's society there are great inhibitions to technological advancement stemming from the government regulation that ridgidly structures what can and cannot be done according to established norms. As an illustration from our experience in Ohio, oil mining is not defined as mining in Ohio law because oil is excluded from mining in the Ohio legal definition of mining. As a consequence the Ohio State Mine Inspector did not have jurisdiction over our underground operations although we were covered by MSHA. The Ohio State legislature is now attempting to change the definition of a mine to include oil mining.

I make the point because the same problem exists in the Windfall Profit Tax Act. When the legislation was being drafted, no one in the drafting process was aware of the growing interest in gravity drainage technology. As a result, neither definition nor mention of oil mining was made in the Windfall Profit Tax Act. Lacking an awareness of the existence of oil mining, even as an oil recovery concept, the Congress had no way of anticipating the adverse effect the Act would have on the economics of oil mining, much less realize that the Act would have a compound adverse and inequitable effect on independent producers, as I will point out.

These facts, however, became immediately evident in our economic research. To our astonishment, it was determined after repetitive legal investigation that oil produced by mining is subject to the highest rate of windfall profit taxation. Being confident that this was an unintended oversight, I have made the effort to inform members of Congress, their staffs and Treasury Department personnel about oil mining and the disincentive to development of oil mining technology that the windfall profit tax presents. I have been encouraged in my discussions by the understanding response of government personnel when oil mining is described and oil mining's potential for adding recoverable oil to our domestic oil reserve is realized. However, I should note a misconception that I have observed is particularly prevalent in the Treasury Department, that of, were oil mining to prove successful it could replace conventional oil production methods and, therefore, were mined oil to be taxed at less than the maximum rate, the door to lower taxation of essentially all oil would be left ajar. While I find such an extension of thinking appealing because of my deep and abiding belief in the future of oil mining, my thoughts don't soar with the same enthusiasm. I know of the problems to be overcome in order to achieve success in oil mining. Oil mining holds no possibility of being an economic panacea to oil production. By its nature, oil mining will always be highly capital intensive and applicable only as a last measure to increase recovery of oil from reserves unable to be recovered by easier, less costly, less risky means. Advances in the technology will be hard won, as they

invariably are, in frontier research. The technology simply needs the encouragement of fair treatment from taxing and regulatory agencies in order to respond to the need of the nation for greater availability and utilization of its energy resources.

Without discussing the merits of the windfall profit tax itself, I would like to express my principle concerns with respect to the taxation of mined oil.

As I have noted oil mining is a fourth stage or quaternary method of recovering crude oil. This fourth-phase recovery method is applicable to properties which can no longer be commercially produced by other methods.

The Windfall Profit Tax Act recognizes the need to encourage greater domestic production as well as the need to optimize oil recovery. Thus, even though oil mining is applied as a fourth-phase recovery process, a mined-oil producer does not have the benefits of lower windfall profit tax rates (as does a producer using tertiary methods), because no provisions exist under the Windfall Profit Tax Act for quaternary recovery methods.

The only way that a producer of mined oil could possibly qualify for the tier-3 tax rate would be to additionally apply "qualified" tertiary injectant methods. Such inequity of taxation of a third-phase recovery system versus a fourth phase recovery method, clearly provides only disincentive to greater domestic recovery using oil mining.

Lacking provisions dealing with mined oil, a producer must attempt to come within one of the present tier classifications -- such as for example, stripper-well oil. Candidate reservoirs for mined-oil production, generally averages 1/2 barrel per day per well. And yet, a producer of mined oil cannot classify his property as an exempt stripper because of the transfer limitation in section 4994(g)(2) of the Windfall Profit Tax Act, unless the property is transferred from an independent producer or is an "unproven" property.

Many abandoned and shallow fields are in stacked or multiple level reservoir fields held by non-independent producers because many leases covering conventionally depleted shallow reservoirs are held by deeper production. Yet, if an independent producer wishes to mine the remaining oil in the depleted sand, the transfer limitations only penalize his innovative and valuable efforts. For example, if a lease is held by a major oil company producing from a deeper reservoir, an independent producer seeking to recover mined oil from a shallower reservoir, cannot qualify for even the independent-producer tax rate. In addition, the properties which are condusive to oil mining are proven by past production even though their principle value may have ceased to be as an oil and gas property under current economics.

If a mined-oil producer operates a property transferred after 1978, which was classified as a tier-1 property prior to transfer because some production existed in 1978 even though later shut-in because further recovery or attempts to increase production were seen as uncommercial, the producer must pay the high tier-1 rate as a result of the transfer limitations of section 4996(e).

Furthermore, were a producer to reclassify a property as, for example, a stripper-oil property based on his production, the reclassification would nevertheless not benefit the producer. Section 4992(d)(3) effectively prohibits the application of the independent-producer rates where the transfer is after 1980. Thus, for mined-oil production under the Windfall Profit Tax Act, it is clearly a "Catch 22" situation. Even though a producer is independent and seeks to produce petroleum domestically, applying a quaternary-recovery method, the Windfall Profit Tax Act provides only discouragement. The independent producer must either pay the high general windfall profit tax rates or he must expend even greater costs in order to qualify the quarternary method as a tertiary project.

The transfer limitations under the independent-producer provisions, as can be seen, present a major obstacle to our development of oil mining concepts to oil production.

It is my hope that the views herein expressed will be helpful to the committee in understanding the inequity of the windfall profit as applied to oil mining so that Congress can redress an understandable oversight which occurred at the time the Windfall Profit Tax Act was passed.

The vital strategic importance of domestic oil reserves and the need to maximize the utilization of our national resources dictate removal of the penalizing provisions of the tax code which are inhibiting private research and development of a technology of potentially major national benefit.

STATEMENT OF WILLIAM B. SPENCE, PRESIDENT, OIL MINING INTERNATIONAL, INC.

Mr. SPENCE. I would like to apologize. I have not presented any written text, because I just became aware of this meeting a few days ago. News travels slowly to Texas.

Senator WARNER. We will keep the record open and you can submit whatever you desire. We are going to keep it open for 2 weeks. We may have another hearing. I am fascinated with the subject.

Mr. SPENCE. To tell you the truth, I basically wanted to wait and see what everybody else had to say. I did not really prepare anything, because of confidentialities. But I have changed my mind and I would like to make a few statements.

The first thing is that currently we have almost concluded the installation of the oil mine in Texas. I am president of a company called Oil Mining International, but basically what we are is just a group of three partners and we contacted some individuals in Europe and we have gone over there and had some discussions with the Thatcher government concerning oil mining and drilled some test holes and did some experimental work over there and came back here to the United States.

I would like to say that I agree with many of the things that have been said here, but my reason for getting into oil mining was not to solve the world energy crisis or to make America independent. Mine was, rather, I think you can make a lot of money doing it and I think people have overlooked the simplicity of it.

Basically, I feel that everybody who has spoken on oil mining thus far has talked about the large capital cost to install the mine and we have found that that was not necessary, I mean depended on relativity. There is plenty of oil at very shallow depth that it does not take $15 to $25 million to install a mine. In my personal opinion, because of the nature of the technology, it is very difficult to find somebody that has the entrepreneur spirit to invest $25 million in a concept that has such limited technical land and also economical proofability of proving data existing on it.

Therefore, we felt that it was necessary to crawl before we even walked. So we put in a modest operation and it has proven out that the flow rates and the things that these gentlemen are theoretically discussing have in fact been proven out in test. Hopefully, we are planning our second mine to begin operation or to start operation in the next month and hopefully by the end of summer we will have installed between 5 and 20 of them.

Our operations are more like guerrilla-type operations, small, not with the magnitude that they are discussing. But hopefully one day we will be able to move into that.

The one thing I would like to say is that I think that the discussions as far as flow rates and that are concerned, I think are rather relative, in that it is impossible, I think, to predict what a flow rate will be, because the nature of every reservoir varies so much that they will all be different.

I also think that to put one large oil mine in could, if it does in fact turn out negatively and you have invested $25 million, I believe one of the problems that exists is that it could attach a

stigma to the whole concept, like what happened in oil shale projects that you had brought up before.

I think basically, and again this is my opinion and I am probably an overly opinionated individual, but I think they built a Cadillac when they could have built a Volkswagen. I think they felt that the pockets were real deep in the pants and they intended to go to the bottom of it. I think that according to Dr. Trent and as Ms. Cobb brought up regarding the windfall profit tax would be probably the most appropriate and the most beneficial thing that the Government could do to help us get started.

Senator WARNER. I am going to look at that and I am highly intrigued with this whole subject. I thank each of you individually and collectively. We will see where we are going to go from here. There has got to be some answers to this question. If legislatively, help is needed, then at least the Senate should address it. Probably other Senators are equally as interested as I and maybe I can be the catalyst to get some consideration here in the Senate on this issue.

It is clear that a reservoir of oil is there waiting to be tapped. You said, Mr. Wimpfen, when we started, this country's national security is dependent on that. Indeed it is and a strategic petroleum reserve and as yet we have not got the mechanics to help it out.

I thank you.

[Whereupon, at 11:30 a.m., the hearing was adjourned.]

APPENDIX

ADDITIONAL MATERIAL SUBMITTED FOR THE RECORD

Alex M. Yarsa
Division Manager
Production Department

Conoco Inc.
907 Rancho Road
Casper, WY 82601
(307) 234-7311

1984 [illegible] 11:59

February 22, 1984

The Honorable John W. Warner
United States Senate
Committee on Energy & Natural Resources
Washington, D. C. 20510

Dear Senator Warner:

Conoco Inc. respectfully declines your invitation to testify before the Subcommittee on Energy and Mineral Resources on the subject of oil mining as requested in your letter to Dan Seelye dated January 27, 1984. Conoco's decision is based on the fact that the North Tisdale oil mining projects are unique to this type of shallow, low pressure reservoir. It is our opinion that the techniques used at North Tisdale to access and produce the oil have no broad application in other oil reservoirs in the United States.

Conoco currently operates two oil mining projects in the North Tisdale field in Central Wyoming. The first project was initiated in June, 1977 and completed in August, 1979 at a total cost of $1,660,000. The project consisted of an "adit", or tunnel, conventionally mined into the hillside for a distance of 985 feet. The "adit" intersected the oil producing Lakota sandstone and six horizontal drain holes were drilled into the oil bearing rock to accelerate the oil recovery by gravity drainage. The average first year's production from the project was 68 barrels of oil per day (BOPD) and 28 barrels of water per day (BWPD) with no gas production. The current producing rate from the "adit" project is 14 BOPD and 11 BWPD with a cumulative recovery of 67,527 barrels of oil (BO) and 21,693 barrels of water (BW).

The initial project appeared to be technically feasible, and as a result, in 1981 a second oil mining project was initiated using a vertical mine shaft to access the Lakota Sand. The shaft project was completed in April, 1982 for a total cost of $2,041,100. Horizontal drain holes were again drilled into the oil bearing sand from the base of the vertical shaft to accelerate oil production. The producing rate from the shaft project was disappointing with an average first year producing rate of 35 BOPD and 25 BWPD. The current producing rate from the shaft project is 15 BOPD and 14 BWPD with a cumulative recovery of 18,564 BO and 16,038 BW. Two papers describing the oil mining projects in more detail are attached for your review.

Conoco currently has no additional plans for future development of the Lakota Sand at North Tisdale using mining techniques. The high initial investment, low oil recoveries, and high Windfall Profits Taxes (60%) combine for very poor economics. An application was made by Conoco to the Internal Revenue Service to have the oil mining projects certified as a tertiary oil recovery process due to its unique nature and high development cost. This certification, which to date has been declined by the IRS, would have reduced the Windfall Profits Tax from a 60% rate to a 30% rate. This action would enhance the economic feasibility of oil mining and possibly justify additional experimentation with oil recovery using mining technology.

Thank you for the opportunity to present testimony on the subject of oil mining. If you have any additional questions on these projects, contact Alex M. Yarsa at the above address.

Sincerely yours,

Alex M. Yarsa

Alex M. Yarsa
Division Manager

dfk

Attachment

NOTE: Should you or any of your Committee Staff desire to inspect our facility at North Tisdale, we would be happy to host such a visit.

cc: R. E. McKee - Houston
Nancie Johnson - Washington, D.C.

SPE

Society of Petroleum Engineers of AIME

SPE 9418

MINING TECHNOLOGY ASSISTS OIL RECOVERY FROM WYOMING FIELD

by Warren F. Dobson and Daniel R. Seelye, Conoco Inc.

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This paper was presented at the 55th Annual Fall Technical Conference and Exhibition of the Society of Petroleum Engineers of AIME, held in Dallas, Texas, September 21-24, 1980. The material is subject to correction by the author. Permission to copy is restricted to an abstract of not more than 300 words. Write: 6200 N. Central Expwy., Dallas, Texas 75206.

INTRODUCTION

An unusual oil recovery project in Wyoming combines aspects of mining and petroleum engineering technologies to increase production from the North Tisdale Field. The project basically consists of a horizontal tunnel, or adit in mining terminology, conventionally mined into a hillside (Fig. 1). The adit provides access to the oil sand from which an array of horizontal drainholes were drilled to varying lengths. At the present time it is the only project known to exist in the U.S. which produces oil using this method.

HISTORY

Utilizing mining methods to produce petroleum from shallow deposits is not a new concept. Mining, in one form or another, has been used to recovery various forms of petroleum for centuries. Its importance, however, has been over-shadowed by conventional oil well development since Colonel Drake successfully drilled for oil in 1859. Petroleum mining can be traced back in history to before 5000 B.C. when deposits were mined in the Sinai Penninsula, Persia, and in the Euphrates River Valley. Ancient Egyptians used mined petroleum for embalming, and sailors have long known the value of tar mined from pits for making their vessels watertight. In more recent history, petroleum mining has been attempted in the United States with varying degrees of success. Projects have been attempted in Pennsylvania, Ohio, California, Texas, Kansas, Utah, and now Wyoming. It was employed in the late 1800's primarily as an alternative to conventional oil well drilling and later as a means of recovering additional reserves from shallow, pressure-depleted reservoirs. In addition to the early American oil mining attempts, two famous mining operations were sucessfully developed in the Pechelbronn Field in France and in the Wietze Field in Germany from 1917 to 1930. These mines were developed during a period of European history when oil was a commodity which was required almost regardless of the cost. In general, however, the petroleum industry has turned away from oil mining as a viable recovery method because of the more favorable economic factors associated with conventional drilling development. Recent developments in world oil supplies and prices are now providing producers with incentives to experiment with mining as an oil recovery technique.

References and illustrations at end of paper.

Lakota Development

The North Tisdale Oil Field is located in the Powder River Basin approximately 70 miles (112.6 km) north of Casper, Wyoming. (Fig. 2) Production was first discovered in the field in 1952 from the Curtis Sandstone at a depth of 1000 ft (304.8 m). The discovery well had oil shows in the shallower Lakota Sand and the following year the first productive Lakota well was drilled. It was completed for 24 BOPD (3.8 m^3/d) and 2 BWPD (0.3 m^3/d) from a zone at 210 ft (64.0 m). Prior to this discovery, the Lakota was known to be oil productive in the area. Local history relates tales of early homesteaders and travellers who used oil obtained from seeps to lubricate wagon wheels.

The Lakota has provided a special challenge since development began in 1953. Production from early wells indicated that the reservoir initially produced through a weak gas drive which was replaced by gravity drainage shortly after completion. Local outcrops have allowed gas to escape and deplete the Lakota reservoir pressure. Typical of gravity drainage, conventional oil wells exhibit low initial producing rates and long producing lives. Lakota development was slow due to the marginal economics of the low volume wells. A total of six producing wells were drilled from 1953 to 1962 which had average initial producing rates of 8 BOPD (1.3 m^3/d) and 3 BWPD (0.5 m^3/d) (Fig. 3). Engineers recognized the fact that less than 2% of the oil in place would be recovered from the Lakota by primary methods. As a result, a one injection well pilot waterflood was tested in 1961 to investigate the feasibility of waterflooding the Lakota. The injection well produced a slight response in an offsetting producer. The one well project was expanded to a single five spot pattern to test the application of a fieldwide flood. The project was installed in 1962 and was discontinued after a significant volume of water was injected and no production or pressure response was noted in the central

producing well or in offset producers. Lakota development halted after the pilot waterfloods due to a lack of success and poor economics. By 1972, all but three of the Lakota wells in the field were plugged, and of these only one continued to produce at a rate of 1.5 BOPD (0.2 m^3/d) and 1 BWPD (0.2 m^3/d). Total conventional recovery from the reservoir since discovery has been only 79,500 STBO (12,640 m^3).

Reservoir Characteristics

The North Tisdale Field is located structurally on the asymmetric, north plunging nose of the large Tisdale Mountain anticline. The steeper western limb of the anticline dips at 10 to 12 degrees, and the eastern limb dips at approximately 4 degrees. The Lakota structure generally parallels the surface topography of the mountain. The Lakota reservoir consists of a large gas cap surrounded by an oil ring which is further defined by a water-oil contact. The vertical depth reaches a maximum of 500 ft (152.4 m) on the crest and ridges of the mountain and decreases in depth in the eroded draws. A number of outcrops are evident in the most severely eroded draws. The average depth of the Lakota is approximately 300 ft (91.4 m) across the field.

The Lakota Sandstone consists primarily of a thin, tight Upper Sand interval and a thicker, oil productive Middle Sand section separated by a thin shaley zone. A water saturated Lower Sand is also apparent in some areas of the field. The Upper Sand averages 12 ft (3.6 m) in gross thickness and is generally described as a light grey, well cemented, medium-to-fine grained sandstone with spotty oil saturation. The Middle Lakota averages 40 ft (12.2 m) in gross thickness and consists of a light grey to tan, medium-grained calcareous sandstone. Well data indicate that the total gross Lakota thickness varies from 30 ft (9.1 m) to 100 ft (30.5 m) with an average thickness of 58 ft (17.7 m). Geological interpretations indicate that the thickness variations and the occasional absence of the Lower Sand are a result of channelling into the underlying Morrison Formation.

The Middle Lakota Sandstone exhibits reservoir rock and fluid properties that make it a good candidate for gravity drainage development. Gravity flow rates are dependent primarily on permeability, oil viscosity, and formation dip. The sand has an average porosity of 18.9% and a horizontal permeability to air ranging from 45 to 3000 md. Saturation determinations from log and core data indicate water saturations in the range of 40-50%. Net pay averages 21 ft (6.4 m) of sand with porosity greater than 10%. The 28° API gravity Lakota crude has a viscosity of 19 cp. at 70° F. (21.1° C.) and a pour point of -10° F. (23.3° C.). Average reservoir temperature is estimated to be 60° F. (15.6° C.). Utilizing the above data, a value of 733 bbl/ac-ft (4116 m^3 oil/m^3) of original oil in place has been estimated.

Planning and Design

In the mid-1970's, rising oil prices renewed an interest in the Lakota, which had remained essentially undeveloped at North Tisdale since 1962. In order to recover additional amounts of "known" Lakota oil, a project was begun to experiment with mining techniques to gain access to the sandstone and drill long horizontal drainholes into the reservoir. A much larger surface area would be created by a horizontal drainhole, and a higher oil production rate would be obtained than was possible with a conventional vertical wellbore. Two alternatives were investigated as possibilities for gaining access to the Lakota reservoir: 1. Drive a horizontal adit into the side of the mountain or, 2. sink a vertical shaft. Geological and mining personnel were consulted to aid in selecting the best approach. Personnel requirements, training requirements, specialized mining equipment, cost, and other factors were considered to determine that a horizontal adit would be the most feasible first choice.

Geologists and engineers selected the project site by combining topographic, geologic, and reservoir information. The site was located near the oil-water contact to maximize oil recovery by gravity drainage. Several mining, environmental, and drilling permits were applied for and obtained from various State and Federal agencies after the mine site was chosen. Well No. 48 was drilled in May, 1977, to verify the presence of oil saturated reservoir rock and confirm the mine site. Well No. 48 also provided information on the depth of the oil-water contact and indicated the angle of decline which the horizontal adit would require to intersect the Lakota Sand. Well logs and drill cuttings indicated the Lakota top at 143 ft (43.6 m) and the top of the Middle Lakota Sand at 162 ft (49.4 m). Approximately 25 ft (7.6 m) of oil saturated reservoir was evident. It was determined that this section of the Middle Lakota in Well No. 48 would be the target point for the adit.

Mining Phase

In June, 1977, portal construction for the adit was completed. A steel security door was installed and the actual mining activity was initiated. Mining was accomplished with conventional drilling, blasting, and mucking equipment by a local Wyoming contractor. Mining of a 9 ft (2.7 m) wide by 8 ft (2.4 m) high adit proceeded by drilling 1 in. (2.5 cm) diameter holes, 5 ft (1.5 m) in length with a pneumatic drill. Several of these holes were drilled into the advancing face of the adit and packed with explosive charges. The charges were detonated from outside the adit. Specialized mining front end loaders then cleaned (or "mucked") out the rock debris. The initial 550 ft (167.6 m) of the adit was driven through weathered sections of the Fuson Shale. The instability ofa these shales required the use of conventional timber supports. Ground movement associated with small faults and swelling of the bentonitic clays in the shales during seasonal wet periods required the installation of steel beams in place of timber for adequate support. At a length of 720 ft (219.5 m) the adit was well within the competent Upper Lakota Sand, and ground control methods were changed from timbering to roof bolting. "Split Set" roof bolts were utilized consisting of a 5 ft (1.5 m) hollow steel tube, 1 1/2 in. (3.8 cm) in diameter, with an open gap along the entire length. The bolts are driven into a 1-3/8 in. (3.5 cm) diameter hole with an air hammer. The friction between the tube and the wall of the hole provides resistance to movement of the ground.

A standard chain link fencing was slipped over the rock bolts and pinned to the roof and walls as protection against aloughing and spalling rock. This type of support was continued until the mining was halted at a length of 985 ft (300.2 m) where the wellbore of No. 48 was intersected. (Fig. 4.)

Ventilation of the adit was accomplished during mining by blowing air down the length of the adit through 18 in. (45.7 cm) flexible tubing to the face. Prior to the adit completion, a more permanent ventilation system was installed. A 22 in. (55.9 cm) hole was drilled to a depth of 176 ft (53.6 m) from the Well No. 48 surface location and cased to 18 in. (45.7 cm). The adit was then advanced to intersect the ventilation shaft and a 30 horsepower (22.4 kW) vane axial reversible fan was installed on the surface. The flexible ventilation tubing utilized during construction was removed, and ventilation is now accomplished by drawing fresh air in the portal, down the length of the adit, up the vent shaft, and through the fan. It is critical for a safe mining operation to maintain an adequate fresh air flow through the mine. The ventilation system meets all requirements set forth by State and Federal gassy mine regulations.

The vent shaft also doubles as an emergency escape route. An escape hoist and cage is installed on the surface which can be lowered into the mine to remove personnel in the event of an underground emergency. The hoist is powered by an electric motor and is also equipped with a back-up generator. The unit was installed and approved in accordance with State and Federal Mine Safety Regulations. These regulations require at least one qualified person on the surface at all times when personnel are underground.

At this point final preparations were made to begin the horizontal drilling phase of the project. A steel production sump tank was bolted into the floor directly below Well No. 48 to serve as a collection point for produced fluids. A conventional beam pumping unit was installed on the surface and tubing, rods, and pump were run down to the sump. (See Fig. 5.)

Drilling Phase

Specialized drilling equipment was used to drill the horizontal drainholes. The machinery had to meet several requirements: 1. The drill had to be compact and easily operated in the confined area; 2. it had to be safe for operation in a gassy atmosphere; and 3. it had to be easily controlled to correct for hole deviation. Deviation control was considered very important since it was desired to remain as close to the bottom of the oil saturated sand section as possible. This would take full advantage of the oil column height and result in maximum recoverable reserves. The drilling equipment used at North Tisdale was developed by Conoco Mining Research for coal seam degasification in underground mines. The compact drill utilized 5 ft (1.5 m) long joints of 2 1/4 in. (5.7 cm) drill pipe to drill a 2-7/8 in. (7.3 cm) diameter hole. The equipment was capable of drilling a hole 2000 ft (609.6 m) in length. The unit was operated totally by hydraulics and controlled by a portable valve control panel located underground. An electrically driven hydraulic power pack was located on the surface, and hydraulic lines were run down a separate 5 1/2 in. (14.0 cm) service hole drilled into the adit. Once the drilling equipment was oriented and secured in position, a 10 ft (3.0 m) long, 7-7/8 in. (20.0 cm) diameter hole was drilled into the wall. In this hole a length of 5 1/2 in. (14.0 cm) line pipe was cemented to serve as conductor pipe during drilling and also to provide a means of controlling flow from the completed drainhole. The remaining length of each hole was left open to the sand. Six horizontal drainholes were drilled. (See Fig. 6.) The holes and corresponding lengths are as follows:

#1	1498 ft (456.6 m)	#4	1700 ft (518.2 m)
#2	248 ft (75.6 m)	#5	970 ft (295.7 m)
#3	420 ft (128.0 m)	#6	1070 ft (326.1 m)

Holes No. 2, No. 3, and No. 5 were terminated at short lengths when clays were encountered and the drill pipe twisted off. The first five holes were drilled in the Middle Lakota Sand, and the sixth hole tested the productivity of the Upper Lakota Sand. The Upper Lakota was found to be non-productive and the drainhole was deviated and completed in the Middle Lakota Sand.

Directional surveying of the drainholes was done at 35 ft (10.7 m) to 50 ft (15.2 m) intervals using a special Sperry Sun survey tool which was pumped down the internally flush drill pipe and retrieved with a wireline winch. Deviation in the vertical plane was controlled by the amount of thrust placed on the bit. The typical deviation range was $\pm$ 5 ft (1.5 m). Horizontal deviation was not as easily controlled. Drilling records indicate that the bit tended to drift upstructure. It was determined that a near bit square stabilizer with additional stabilizers in the drill string would produce a relatively straight hole.

The drill assembly was developed primarily for use in drilling coal. Sandstone, being a much more abrasive material, caused several problems with the equipment. Drill pipe failure due to insufficient pipe wall strength was quite common, and a great deal of time was spent in fishing. Since the hole size and drill pipe size were non-standard, conventional oil field tape taps and spears had to be modified for fishing. The frequency of drill pipe failures was reduced later in the drilling by the addition of a polymer in the fresh water mud system. The polymer reduced friction between the pipe and hole wall and inhibited the swelling of clays.

Bit selection to accommodate the sand was initially a problem. Carbide insert bits were tried, but penetration rates were very poor and the bits dulled rapidly. Cone bits were also tried, but it was found that they tended to wander regardless of the thrust applied. A specially designed diamond bit proved to be the best performer. In addition to good deviation control, penetration rates averaged 3.3 ft/min. (1.0 m/min.) and rates as high as 6.7 ft/min. (2.0 m/min.) were obtained several times. The average footage drilled during a good eight-hour shift was 125 ft (38.1 m).

Separation of the drill cuttings from the mud system was accomplished in three 4 ft x 8 ft x 2.5 ft high (1.2 m x 2.4 m x 0.8 m) mud tanks located underground near the drill. Fluid was siphoned off the top of each successive tank and piped into a centrifugal mud pump. Very early in the drilling it was evident that extremely fine powdered sand was carrying through the mud system causing damage to the pump. The problem was solved by installing a progressing cavity pump with a flexible rubber stator. When the mud tanks were filled with cuttings, they were hauled out to the surface and dumped.

Production Controls

The pumping unit on Well No. 48 is controlled by a level sensing bubble tube apparatus located in

the underground main production sump. A constant air flow rate of 2 CFH (0.057 m^3/hr.) travels down a 1/2 in. (1.3 cm) open ended tube which is submerged in the sump. The hydrostatic head above the bottom of the bubble tube is transmitted as air pressure to a pair of head switches at the surface. As the liquid level on the sump reaches a preset level, the pump is started. As the fluid level drops to a preset low level, the pump is stopped.

Drainhole No. 6 is located approximately 250 ft (76.2 m) back from the face of the adit and the main production sump. This required the installation of a small sump at No. 6 with two air-operated diaphragm pumps to transfer fluid to the main sump. One pump is the primary fluid transfer pump, and the second pump acts as a back up. The back up pump operates in the event of a primary pump malfunction and also when a high fluid level exists in the sump. These pumps are controlled by float switches which automatically start and stop the pumps.

The fire alarm system is comprised primarily of 1/4 in. (0.6 cm) polyethylene tubing hung from the mine roof in the oil saturated section of the adit. The tubing is connected to an air actuated cylinder and fire-safe valve on the drainholes. A compressor on the surface supplies a constant 50 psi (446 kPa) pressure to the system, holding the fire-safe valves in an open position under normal operations. In the event of an underground fire or explosion, the polyethylene tubing will melt causing a loss of air pressure and thereby automatically shut in the drainholes to prevent produced oil from continuously feeding a fire.

The operation of the ventilation system is constantly monitored by a flow-no-flow and vacuum/pressure probe in the ventilation piping. If a continuous flow of air past these monitors is not maintained, an air operated siren is activated which is audible both underground and on the surface. It must be noted that due to mining regulations, ventilation must be maintained at all times. However, during the producing life of the project a low volume fan moves air at approximately 7000 CFM (198 m^3/min.) when no personnel are in the mine. The main, or high volume fan, which was used during drilling, must be used when any personnel enter the mine. This fan will move air at a rate of 17,000 CFM (481 m^3/min.).

A washline system consisting of 1 1/4 in. (3.2 cm) black pipe has been installed in three of the six drainholes. The purpose of the washline is to flush accumulated sand which may collect in the drainholes and also to provide a means for various stimulation treatments. The washline system is connected to the surface through the 5 1/2 in. (14.0 cm) service hole drilled into the mine.

In addition to these alarms and controls, a telephone communication system between the surface and underground has been installed. The telephones are located at two stations underground, one at the portal and one at the surface location of Well No. 48.

The adit is entered and inspected by personnel trained in accordance with State and Federal laws. The project was initially inspected monthly to make final control adjustments on the production equipment. All maintenance procedures are now done on a quarterly basis. In addition to the company inspection, the project is also inspected quarterly by a Deputy State Mine Inspector and a Federal Mine Safety and Health Administration Inspector.

Production Performance

Project construction and horizontal drilling were completed on August 3, 1979, and the producing phase of the project began. A total of 34,312 STBO (5455 m^3 and 12,544 EW (1994 m^3) have been produced from the project as of April 1,1980. The average first year producing rate was 68 BOPD (10.8 m^3/d) and 28 BWPD (4.5 m^3/d) (Fig. 7). The initial decline of production was 56% per year; however, the initial sharp decline is due to the effect of gas cap expansion. The production of fluids from the project is quickly depleting the low pressure (20 psi) remaining in the reservoir. Gravity drainage will become increasingly dominant as the pressure continues to decline. Production trends over the past three months indicate that a levelling out of the decline is beginning to occur showing the effect of a gravity drainage mechanism. It is now projected that the production will level out at approximately 40 BOPD (6.4 m^3/d) and decline at a rate of 6% per year.

CONCLUSION

The Lakota Gravity Drainage Project at North Tisdale provides a successful example of how mining methods can be used to recover oil. It is planned to continue the development of the Lakota in the area with a vertical shaft. A large diameter shaft will be constructed to provide an access to an underground drilling chamber. Horizontal drainholes will be drilled from the underground chamber into the reservoir in a manner similar to the first project. However, the horizontal drilling equipment has been redesigned to reduce downtime due to mechanical failure and drill pipe twist offs. As the new technology associated with mining for petroleum is improved, these techniques will undoubtedly be applied in other areas to other low pressure oil reservoirs.

Experimentation with various stimulation treatments such as chemical wash treatments, a carbon dioxide flush, and possible experimentation with steam injection is also being considered for the horizontal drainholes. Future plans also include reservoir repressuring with air injection in an effort to maximize recovery.

In summary, the North Tisdale Gravity Drainage Project has illustrated that:

1. Mining for petroleum is a technically feasible concept in a shallow, low pressure sandstone reservoir;

2. Improvements in horizontal drilling equipment will increase operational efficiency and reduce costs; and

3. Mining for petroleum will become more economically attractive as oil prices continue to rise.

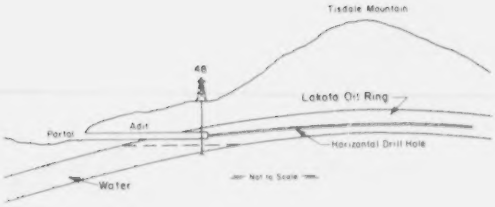

Fig. 1 - Generalized Conception of Project.

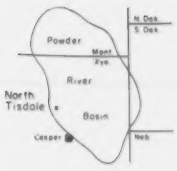

Fig. 2 - North Tisdale Location Map.

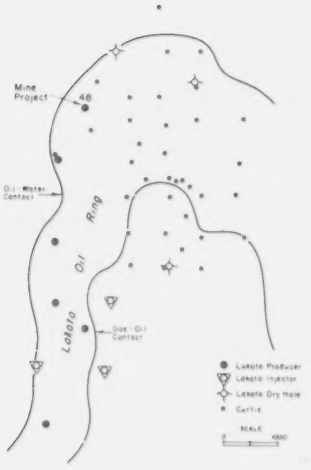

Fig. 3 - North Tisdale Producing Wells.

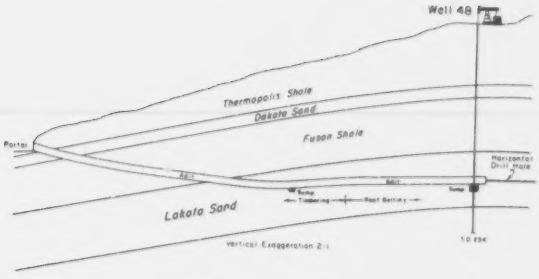

Fig. 4 - Actual Adit Cross-Section.

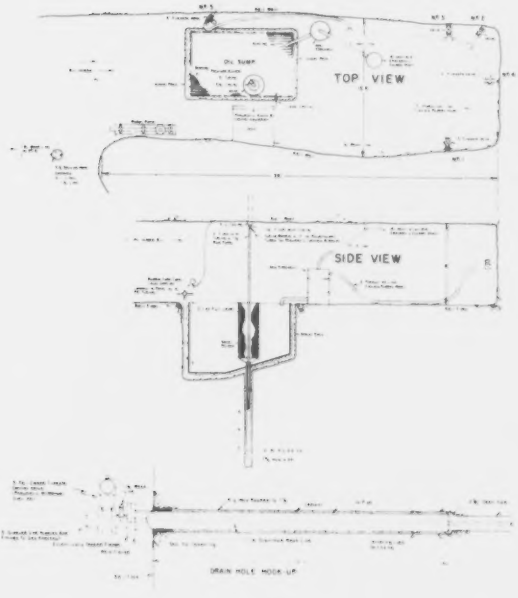

Fig. 5 - Underground Production Equipment Layout.

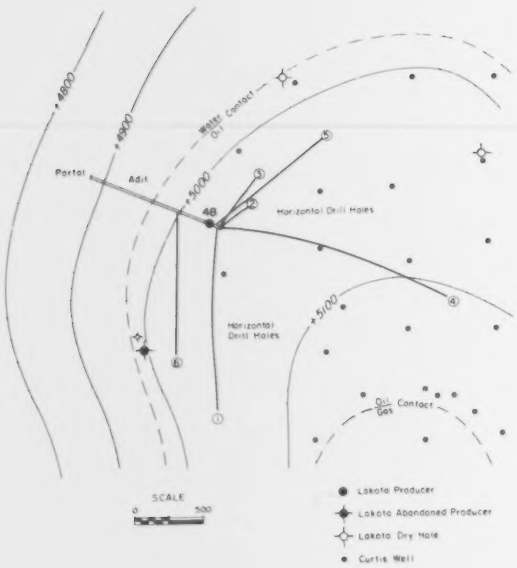

Fig. 6 - Horizontal Drainhole Pattern.

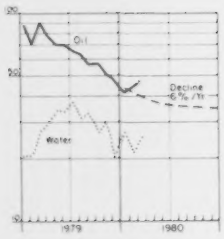

Fig. 7 - Production Performance Curve.

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The North Tisdale Mine: Gravity Drainage Project

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ABSTRACT

THE NORTH TISDALE MINE: GRAVITY DRAINAGE PROJECT discusses the use of mining technology to recover shallow oil reserves from a reservoir operating almost entirely under gravity drainage. Development of this reservoir by conventional methods was not economical due to low production rates. Two different techniques have been used to develop the 300 ft (91.4 m) deep Lakota sand in Wyoming's North Tisdale Field. The first project was begun in 1977 with access to the Lakota being gained through a horizontal tunnel or adit. The second project, initiated in 1981, will provide access to the Lakota through a 16 ft (4.9 m) diameter vertical shaft. In both projects, the plan was to enhance the gravity drainage effect by boring horizontal holes along the strike of the formation from a drilling chamber in the formation. The oil drains down-dip into the horizontal holes, is collected in a sump, and is then pumped to the surface by a conventional beam pump. The horizontal holes are currently being drilled in the vertical shaft. A new technique for drilling drain holes is being tried in the vertical shaft project. A horizontal hole is drilled first, then a turbo-drill is being used to drill several relatively short deviated holes off of the horizontal hole in order to expose more of the formation. The production history of the adit project as well as cost figures, production projections, and economics of the projects are also presented.

INTRODUCTION

Two mining projects have been undertaken in the North Tisdale Field in Wyoming (Figures 1 and 2) to aid in recovering oil by gravity drainage. The first project began in 1977 when an adit, or horizontal tunnel, was dug into North Tisdale Mountain a distance of 965 ft (300 m) to gain access to the oil-bearing Lakota formation (Figure 3). Six horizontal holes were then drilled from a drilling chamber at the end of the adit in the Lakota formation to provide drainage channels from the formation into the adit. The adit project was covered in a paper by Dobson and Seelye.[1] The second project was begun in early 1981 when a 16 ft (4.9 m) diameter vertical shaft was sunk to a depth of 235 ft (71.6 m) to gain access to the Lakota formation (Figure 4). Four 2000 ft (609.6 m) horizontal bore holes are currently being drilled into the formation from the drilling chamber at the base of the shaft. In addition, directional "spurs" are to be drilled off of each bore hole, thus exposing more formation directly to gravity drainage (Figure 5). This paper briefly recaps the major details of the adit project, then discusses the shaft project and the major economic factors of the overall gravity drainage projects in the North Tisdale Field.

References and illustrations at end of paper.

LAKOTA RESERVOIR

The North Tisdale Field is located on the northern nose of a doubly plunging, assymetrical anticline (Figure 2). The anticline forms a topographic high known as Tisdale Mountain which has a surface expression about 10 miles (16 km) by 5 miles (8 km) with maximum topographic relief of about 1000 ft (304.8 m). The eastern flank of the structure dips at an angle of 4 to 6 degrees and the western flank dips at an angle of 10 to 12 degrees. Steep draws cut into the western flank of the mountain, reaching almost as far as the crest of the Lakota structure.

The vertical depth to the Lakota sand in the area of the gravity drainage project is nominally 300 ft (91.4 m); however, the formation is much shallower in the heavily eroded draws that cut into the mountain. The Lakota actually outcrops in some places due to the erosion of the overlying formations. Oil accumulation in the Lakota is confined to an oil ring that has an oil column of 180 ft (54.9 m) between the gas-oil contact at a depth of 5150 ft (1570 m) above sea level and the oil-water contact at a depth of 4970 ft (1515 m) above sea level. The reservoir pressure, obviously never very high, has been dissipated, partly by production and partly by leaking off at the outcrops of the Lakota in the draws.

The gross thickness of the Lakota, based on well logs, varies from 30 ft (9.1 m) to 100 ft (30.5 m). In the area of the gravity drainage

project, the Lakota consists of a 12 ft (3.7 m) thick, tight upper sand interval that is not oil productive and a 40 ft (12.2 m) thick, oil productive middle sand section. In part of the field, there is also a lower sand interval that is water productive. The Middle Lakota oil reservoir exhibits rock properties which make it a good candidate for gravity drainage. Core and log data indicate the sand has an average porosity of 18.9%, a horizontal permeability to air ranging from 45 to 3000 md, and an oil saturation of approximately 50%. There is an average of 21 ft (6.4 m) of net pay in the area of the project. The original oil in place has been calculated to be slightly more than 6 million stock tank barrels (953,924 m^3) in the gravity drainage project area.

HISTORY OF LAKOTA DEVELOPMENT

Development of the Lakota reservoir by conventional methods was not found to be economical due to the low production rates of the wells. The possibility of oil production from the Lakota was first noticed in 1952 when oil shows were observed in the Lakota section while drilling wells for the deeper Curtis formation. In 1953 the first Lakota well, No. 2, was drilled and initially produced at a rate of 24 BOPD (3.8 m^3/d) and 2 BWPD (0.3 m^3/d). Over the next nine years, six more Lakota wells were drilled with initial rates averaging 8 BOPD (1.3 m^3/d) and 3 BWPD (0.5 m^3/d). The apparent producing mechanism was a weak gas drive which was soon depleted in the drainage area of each well, resulting in the wells producing primarily by gravity drainage. A typical decline curve of a Lakota producer (Figure 6) shows the rapid initial decline typical of a gas drive which then levels off at a very low production rate with almost no decline that is typical of gravity drainage.

It became evident early in the life of the reservoir that only a very small portion of the oil in place would be recovered by primary means. Therefore, in 1961 a small pilot waterflood project was tried. Water was injected into one well, No. 36, and some response was noted in an offset well, No. 41, after two months. As a result of this response, it was decided to expand the waterflood by setting up a single five spot pattern around well No. 41 (Figure 1). Over a period of 12 months a total of 235,000 BW (37,362 m^3) was injected without any response from the oil producer. At that point, the project was terminated and today only one conventional Lakota well remains on production, No. 35, at a production rate of 1.4 BOPD (0.2 m^3/d). Cumulative oil production from the Lakota by conventional methods to date is 81,000 barrels (12,878 m^3).

In the 1970's rising oil prices caused a renewal of interest in establishing production from the Lakota. Studies were initiated to ascertain what techniques might prove feasible for developing the reservoir. A review of the history of the reservoir indicated that it would be fruitless to try to waterflood the reservoir again or to try gas cap injection as indications were that the gas cap would not hold pressure due to leakage at the outcrops. Therefore, the investigations centered on finding a way to improve the rates of production that could be obtained from the natural gravity drainage. The obvious way to accomplish this was to increase the amount of formation that would be exposed to the effects of the gravity drainage. Investigations of the ways to accomplish this led to the first project which was to gain access to the formation by excavating an adit through the mountain and then providing the increased area of formation exposed to gravity drainage by boring horizontal holes through the formation.

ADIT PROJECT

The adit project has been reported in detail in an earlier paper by Dobson and Seelye (Ref. 1). The purpose of undertaking the adit project was to prove that commercial rates of production could be obtained from the horizontal drainage holes drilled into the Lakota formation. The adit location was chosen after examining the reservoir data, the geological data, and locating the most favorable topographical location. It was desired to locate the horizontal drainage holes as near to the oil-water contact as possible, thus the maximum oil column would be available to provide oil recovery. The topographical location was actually a most important factor as it determined the length of the adit, and thereby a large part of the cost of the project.

After the adit site was chosen, Lakota well No. 48 was drilled to provide core for determining reservoir properties, up to date logs for formation analysis, and to locate the oil-water contact more exactly. The well did prove to have acceptable reservoir properties and to be favorably situated in relationship to the oil-water contact. The top of the Lakota was at a depth of 143 ft (43.6 m) and the Middle Lakota target was found at 162 ft (49.4 m). There were 25 ft (7.6 m) of net pay in the well.

Mining operations were begun in June 1977 and completed in July 1979 with an adit length of 985 ft (300 m). The adit was 8 ft (2.4 m) wide by 8 ft (2.4 m) high for most of this length but was widened to 12 ft (3.7 m) at the end to provide sufficient room for horizontal drilling operations. Special horizontal drilling equipment was used for the horizontal boring operations. This equipment was developed by CONOCO's Mining Research Division for use in demethanization of coal mines. The drilling machine was a compact, hydraulically powered unit designed to operate in the gassy atmosphere that can occur in coal mines. This machine consisted of a steel beam framework that contained the rotary drive and the horizontal thrust unit and a control panel. The power unit was located on the surface, out of the gassy atmosphere, and was connected by conventional piping to the drilling machine. A 2.25 inch (5.7 cm) OD, 1.91 inch (4.9 cm) ID drill pipe in 5 ft (1.5 m) joints was used to drill a 2 7/8 inch (7.3 cm) hole. Initially, conventional carbide insert bits and cone bits were used, but were found to be unsatisfactory. Specially made diamond bits were tried and performed adequately. A survey tool was adapted for use in the horizontal drill pipe. Six holes were bored (Figure 1), ranging in length from 248 feet (75.6 m) to 1700 ft (518.2 m). The major improvements that were made in the equipment before the start of the next project, as suggested by Dobson and Seelye[1], related to improving the drilling machinery. Generally the equipment was increased in size, strength, and power output to prevent mechanical failures.

VERTICAL SHAFT PROJECT

Suitable sites for additional adits were not found, therefore, three core holes were drilled to the south of the adit (Figure 1) to locate a site for sinking a 16 ft (4.9 m) diameter vertical shaft to gain access to the Lakota formation. The best location was determined to be at well No. 54. This well penetrated 50 ft (15.2 m) of oil saturated sand from 193 ft (58.8 m) to 243 ft (74.1 m) with 25 ft (7.6 m) of net pay. The core porosity ranged from 4% to 30%, averaging 24%, and horizontal air permeabilities were as high as 2300 md, with an average of 900 md (Figure 7). Well No. 54 was put on production with a conventional beam pumping unit and tested at a rate of 3 BOPD (0.5 m^3/d). The other two core holes provided information on the Lakota structure as well as confirmed the oil-water contact in this area.

There are essentially two techniques that are commonly utilized to sink shafts of this size and depth. The older method is by "blasting and mucking" in which the shaft is sunk by alternately loosening the rock by blasting, then removing it by mucking it out or placing the loosened material into buckets and lifting it out of the shaft with the hoist. As the shaft descends, the wall is cased with reinforced concrete at intervals of 10 ft (3 m), using steel concrete forms. The second, newer technique is to use big hole drilling equipment such as that developed for drilling blast holes for nuclear testing in Nevada and Alaska. This technique is much faster and was thought to have been preferable; however, the cost would have been considerably more than for the conventional mining technique according to bids received from contractors. A big factor in the higher cost for drilling was the mobilization and de-mobilization costs for a single shaft. If a series of shafts were to be drilled, these costs would be spread out over all the shafts and the drilling costs would be less. It is possible the big hole drilling costs will become competitive as the technique becomes more widely used.

Shaft construction was begun in April 1981. The shaft itself was completed at a depth of 235 ft (71.6 m) in September 1981 (Figure 4) and the excavation of the drilling chamber at the bottom of the shaft was begun. Although the sinking of the shaft had been accomplished with few problems (excepting some surface equipment breakdowns), the chamber excavation was hampered and delayed because of the continual sloughing of the unconsolidated, oil saturated Lakota sands. The nature of the Lakota at this location was quite different than the experience at the adit had led us to expect. The sand was much more susceptible to disturbance, indeed, as the miners and equipment moved in the chamber, the floor would turn to a semi-liquid and had to be removed in order to gain a footing. Because of the nature of the sand, i.e., the lack of bearing capacity, the dimensions of the chamber had to be changed. The original plan for the chamber called for it to be 18 ft (5.5 m) wide and 12 ft (3.7 m) high; however, the mining engineer advised that the chamber be narrowed to a width of 14 ft (4.3 m) to provide better roof support. Also the spacing on the roof support bolts was changed from 5 ft (1.5 m) centers to 2.5 ft (0.8 m) centers to improve the support. A refuge chamber was excavated 8 ft (2.4 m) high, 8 ft (2.4 m) wide, and 14 ft (4.3 m) long in the side of the drilling chamber to provide for personnel safety in case of an underground emergency. A 7 in (18 cm) life support hole drilled from the surface to the refuge chamber provides air, water lines, and telephone communications. The chamber has an explosion proof and fire resistant door and is lined with concrete and steel.

When well No. 54 was drilled, a conventional drift log type of directional survey was run to locate the bottom hole location which was to be the target of the drilling chamber. However, when the target was reached, the well bore had not been found. The calculations of the drift log were checked and found to be correct. It was then concluded that the drift log was not accurate enough, even at this relatively shallow depth of the well. The well was re-surveyed with a gyroscopic survey and the bottom hole location was found to be 12 ft (3.7 m) away from that determined from the drift survey. The drilling chamber had to be extended 12 ft (3.7 m) to reach the well bore.

Horizontal drilling is now underway, utilizing newly designed drilling equipment (Figure 8), including the drilling machine, drill pipe, and bits. The equipment was altered to alleviate the problems encountered during the adit project. The drilling machine itself is entirely new. The components of the machinery, i.e., the rotary head, the thrust carriage, and the framework all have greater capacity and strength than the original drilling machine. The drill pipe is 2 7/8 inch OD (7.3 cm) with a 0.25 inch (0.6 cm) wall thickness, considerably heavier and stronger than that employed in the adit. The bits being used are 3-1/4 inch (8.3 cm) "Strata-pak" bits. The drill pipe and drilling assembly have both internally and externally flush joint connections. Hole deviations will be controlled by changing the rotational speed and the thrust on the bit. In cases of extreme hole deviation, an oriented turbo-drill may be used to correct the hole. A "single shot" survey tool on wireline is pumped down the drill pipe into beryllium-copper drill collars to obtain data for plotting the deviations. The tool is retrieved by the wireline.

Two of the drainage holes will be drilled to the north of the shaft and two to the south, all approximately parallel to the strike of the formation. It is planned to use an oriented turbo-drill to drill "spurs" off of the main drainage holes (Figure 5) to increase the amount of formation exposed to gravity drainage. As is the case in the horizontal drilling equipment, the turbo-drill and related equipment were developed for use in coal mining.

The production control equipment in the shaft project will be similar in design to that installed in the adit. Production will be collected in a sump directly below the well bore; in fact, the well tubing and rod pump extend down into the sump. As in the adit, a conventional beam pumping unit and rod pump is used to lift the production to the surface. The beam pumping unit is controlled by a sump level sensing apparatus which consists of an open-ended tube through which air is circulated. The end of the tube is set in the sump deep enough for the oil to cover the open end of the tube. The air flow will be diminished and the air pressure in the tube will increase as the level of the oil

rises above the end of the tube. The increase in air pressure triggers the controls on the pumping unit and it is started pumping. Likewise, when the fluid level in the sump falls, the air pressure decreases and the pumping unit is stopped.

As the subsurface facilities will be occupied occasionally, it is a requirement that a fire alarm system be installed. In both the adit and the shaft, this system is made up of 1/4 inch (0.6 cm) polyethylene tubing hung from the roof. A constant air pressure of 50 psig (345 kPa) is maintained on the system at all times to keep the drain hole valves in the open position. In case of an underground fire or explosion, the tubing would quickly melt actuating an audible alarm and causing the air-actuated valves on the individual drainage holes to be closed. This will stop any more oil from draining into the chamber. Ventilation of the chamber is also required. When the chamber is not occupied, a low volume fan will provide 12,000 CFM (344 m^3/min) while a larger fan will provide 24,000 CFM (687) m^3/min) when there are people below ground. The ventilation system is also equipped with an air heater on the air intake piping to provide heat below ground in the winter.

ECONOMICS

The initial producing rate from the adit was 89 BOPD (14.1 m^3/d) and the first year's production averaged 68 BOPD (10.8 m^3/d). This was considerably higher than the 39 BOPD (6.2 m^3/d) that was estimated from gravity drainage equations (Ref. 2). The high rate was apparently due to additional reservoir energy other than the gravity drainage. The rate fell rapidly (Figure 9) and has currently stabilized at 29 BOPD (4.6 m^3/d). This is a 6% per year decline rate, thought to be typical of gravity drainage. Cumulative recovery from the adit through 1981 has been 54,467 barrels (8660 m^3). Ultimate recovery from the adit, based on decline curve projections, is expected to be 178,000 barrels (28,300 m^3) over a producing life of 30 years. The total investment to develop the adit was $1,660,000 or $9.33/bbl ($58.68/m^3). Operating costs for the adit excluding any taxes have been about $3.50/barrel ($22.01/m^3).

Although it is too early in the shaft project for accurate projections of production, there are some reasons to expect a higher production rate from the shaft. The overall drainage hole length will be 4000 ft (1219 m) compared to the 2500 ft (762 m) in the adit and the formation dip is greater at the shaft (12 degrees vs 8 degrees). The cost of the shaft is expected to be $1,910,000 or $6.03/barrel ($37.93/m^3) for the projected ultimate recovery of 317,000 barrels (50,400 m^3) over a 38 year life.

CONCLUSIONS

1. The actual production to date indicates that the development of the Lakota sand by using mining techniques is technically feasible. However, the profitability of such ventures based on the performance of the adit is, at best, marginal.
2. No further development can be recommended, pending the results of the shaft.

REFERENCES

1. Dobson, W. F., Seelye, D. R., "Mining Technology Assists Oil Recovery from Wyoming Field," JPT (February 1982) 259-265.

2. Muskat, M: Physical Principles of Oil Production, McGraw-Hill Book Company, Inc., New York City (1949) 487.

SI Metric Conversion Factors

ft x 3.048*	E-01	= m
in x 2.54 *	E+00	= cm
bbl x 1.589 873	E-01	= m^3
psi x 6.894 757	E+00	= kPa
miles x 1.609 347	E+00	= km
cu ft x 2.863 64	E-02	= m^3

*Conversion factor is exact.

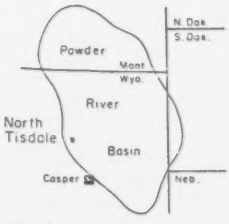

Fig. 1

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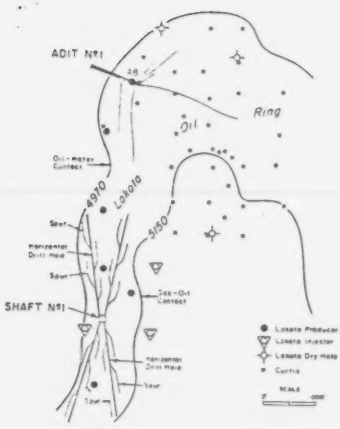


Fig. 2

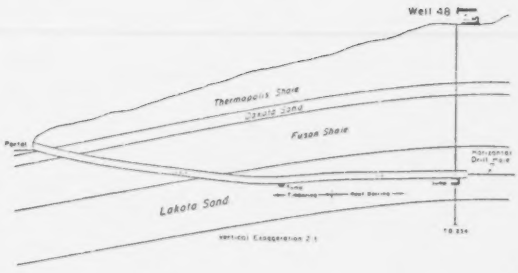


Fig. 3

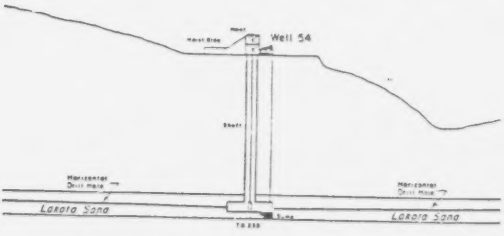


Fig. 4

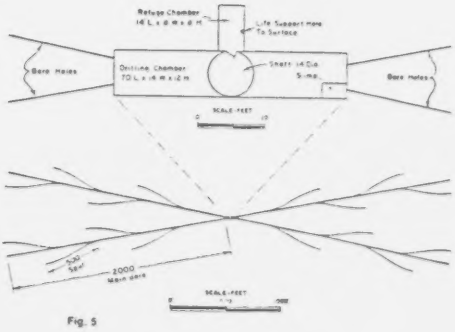


Fig. 5

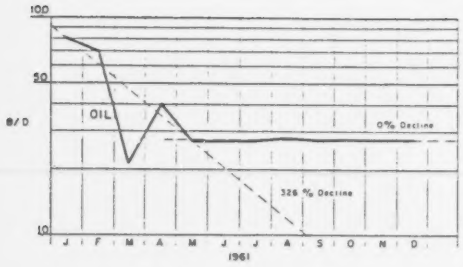


Fig. 6

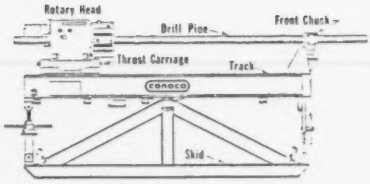


Fig. 8

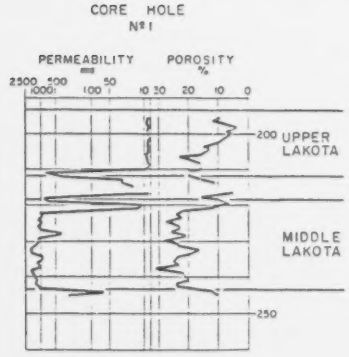


Fig. 7

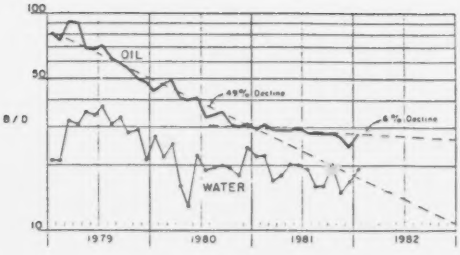
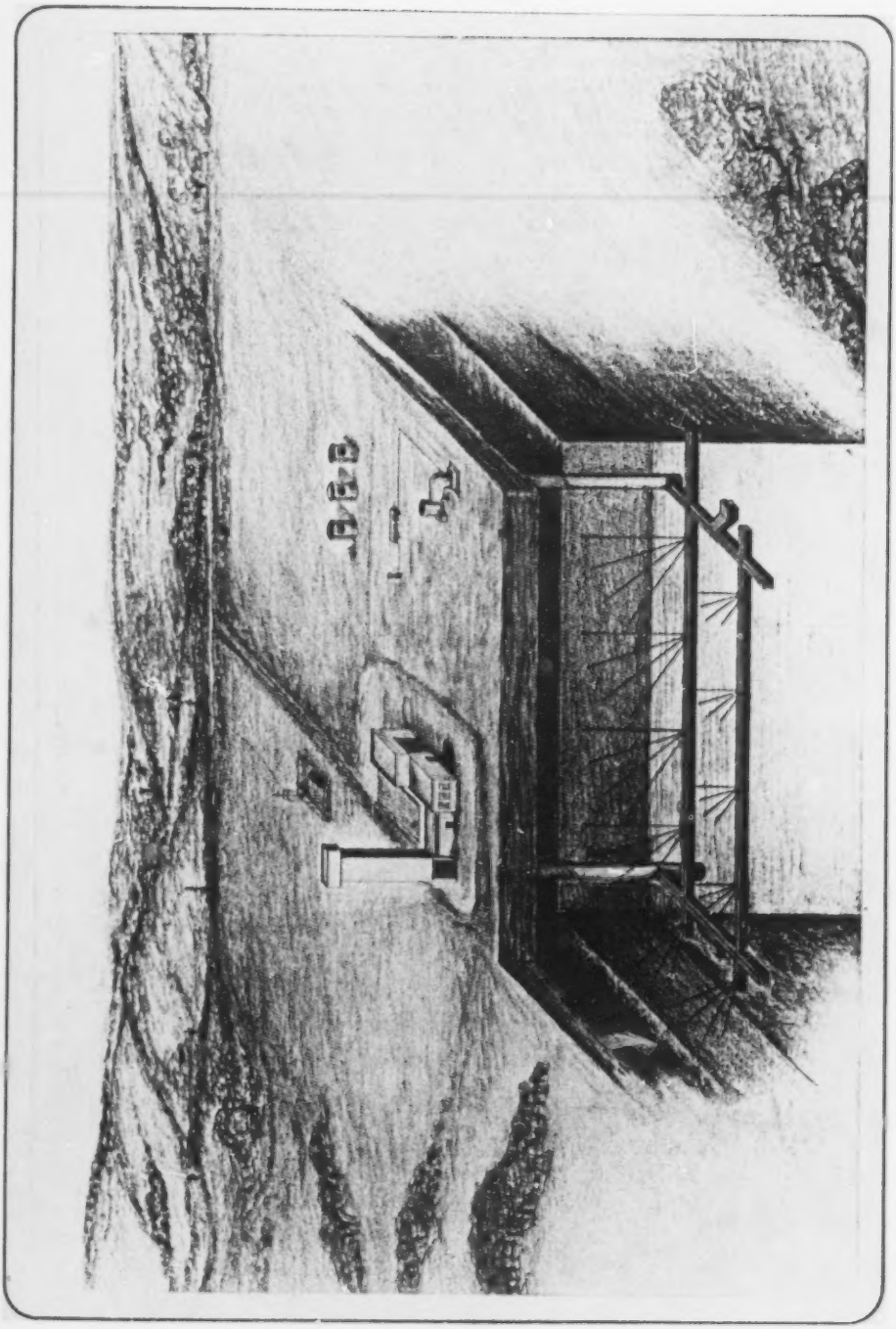


Fig. 9

GRAVITY OIL RECOVERY



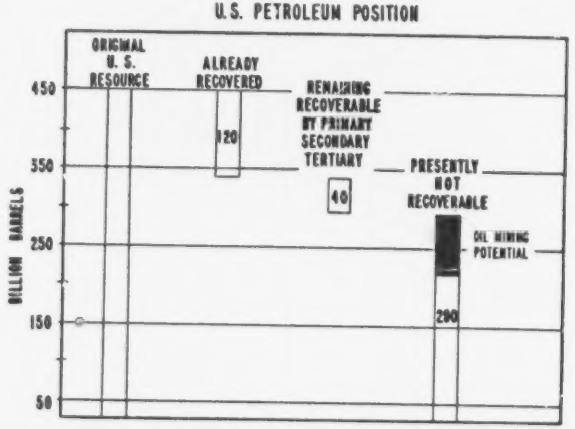
MINERALS GROUP
ALTERNATE ENERGY DIVISION
December 16, 1983

GRAVITY OIL RECOVERY

Executive Summary

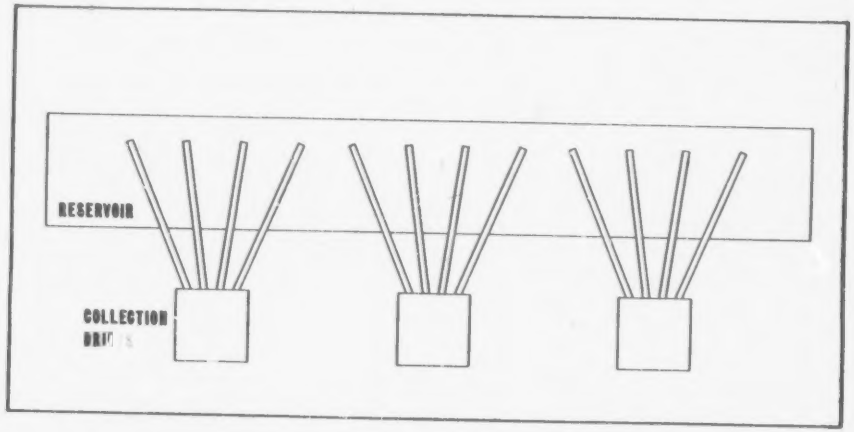
Background:

For hundreds of years man has continued his quest for more efficient methods of petroleum recovery. And, in fact, we have progressed a long way from the days of digging a pit or scooping up a bit of lubricant from a handy oil seep. Yet, overall recovery rates continue to average less than 40% of the original available resource. The extent of the problem is well illustrated by the following graph:



The left hand bar represents the 450 billion barrels of crude thought to have originally been present in the continental United States. The second bar represents the 120 billion barrels already extracted, and the third bar the 40 billion barrels most experts estimate will be recovered by our most sophisticated present day techniques. When all this has been accomplished, there will still be 290 billion barrels left in the ground, which is nearly double that produced since Colonel Drake drilled his first well in Pennsylvania.

One of the more promising current options for significantly increasing recovery in many abandoned fields involves one of a number of methods encompassed by the broad term Oil Mining.



The simplest and hence most economically attractive method of oil mining is called Gravity Oil Recovery (GOR). In this method, development openings are created directly beneath the reservoir, in a competent formation, using conventional mining techniques. These openings, called drifts, are placed on a regular geometric pattern, and spaced to achieve whatever degree of coverage is required by drainage holes drilled upward into the reservoir. From that point on, oil flows by gravity alone into a system of collection pipes throughout the mine to a collection sump.

Success and Failures:

With so many barrels of oil left in the ground at the conclusion of primary production, it is not surprising that oil mining has maintained its attraction over the years. Unfortunately, for every successful venture there have been many more failures.

Most early U.S. gravity drainage projects relied on horizontal holes drilled near the base of the reservoir for fluid collection, and theoretically this was an excellent idea...the more hole area exposed to the reservoir under the highest possible hydrostatic head, the more oil should be collected in the shortest possible timeframe.

What many operators did not fully appreciate at the time was that permeability barriers within their reservoirs effectively blocked or seriously retarded vertical mobility to the extent that recovery was limited to that portion of the resource between the hole and the next higher permeability barrier.

Another common mistake was underestimating the profound effect of viscosity on flow rates in a strictly gravity drive situation. When one couples frictional resistance with very small hydraulic heads due to closely spaced permeability barriers, it is easy to see why so many early operators were disappointed.

Low oil price was a third reason for failure in that the mining cost of many early ventures completely overwhelmed profitability; particularly when it was so inexpensive to find rich new fields by conventional drilling.

Some of the larger successful ventures over the years include the Pechelbronn Field in France where three mines operated from the late 1800's to 1953, the Wietze Field near Hanover where the Germans mined 25% of their oil during World War II, and the Yarega Field in the Soviet Union where an expanding 7500 BOPD operation is continuing on a project that has been in operation since the early 1940's.

Advantages Of GOR:

The bulk of the remaining undeveloped oil reserves in the continental United States are either very deep or offshore. GOR, on the other hand, is targeting at shallow, depleted reservoirs with greater than 60% of the original resource remaining. Many of these fields are unattractive for further conventional, secondary or tertiary development because of the high number of unrecorded and abandoned holes. Where the cost of finding conventional crude now averages a third of the cost of a barrel of oil, GOR targets are already located and well defined. Thus, exploration costs will be limited to those core holes necessary to ascertain the quality and quantity of remaining oil in place.

The initial, targeted reservoirs are of a quality that will not require expensive Enhanced Oil Recovery techniques such as steam or hot water to achieve acceptable flow rates. The oil will be of pipeline quality without upgrading or special handling techniques.

By locating the collection sites directly beneath the reservoir, we optimize the effects of gravity drainage. Further, it puts us in a position to economically penetrate the formation with a high density of holes, thus increasing the odds of draining untapped areas left by primary production, improving the overall rate of recovery, and thereby the rate return on investment.

Technologically speaking, there is no risk. There are no expensive equipment development programs to be considered and only well proven mining and production tehnology will be utilized. Overall it is a very simple operation, using off-the-shelf equipment.

Where Phillips Stands Today:

For over a year, Phillips has had a full time task group assigned to developing a program aimed at demonstrating the economic potential for an oil mining business line. During this period we have conducted an extensive search for sites and developed a computer based drainage model which we believe to be unique. We have prepared a number of cost estimates, and run numerous economic sensitivities in order to more fully understand the more critical factors in selecting a successful initial project site.

All recent studies, including our own, indicate that a point in time has been reached when Gravity Oil Recovery is competitive with conventionally found crude. The reason for this, as stated earlier, is that the cost of finding new reservoirs has risen to a third, and in some cases a half the cost of a barrel of oil. What we are now able to do is trade off higher GOR development costs against high exploration costs of conventionally produced crude.

Base Case Economic Study:

Over and above certain specific reservoir characteristics necessary for drainage, we have concluded that an initial project should be selected on the basis of the following:

The reservoir should contain no less than 8,000 barrels of oil per acre, of which 50% should be recoverable during an economically acceptable timeframe.

Since economics can be greatly enhanced by spreading capital costs over a ten year project life, we should be looking at reservoirs in excess of 3,000 acres.

Depth should be limited to around 1,000 feet to minimize the single largest cost item which is access and ventilation shafts.

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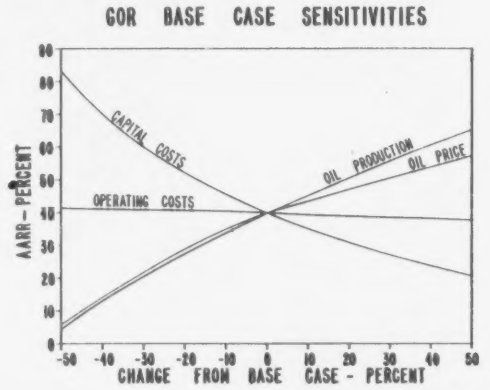
Such a project will require a $51 million preproduction capital investment, and will continuously produce 3,000 barrels of oil per day over its 10 year operational life span.

The indicated AARR for such an operation would be on the order of 39% with anticipated payout occurring approximately two years following initial production.

During the course of such a project, a total of 12 million barrels of oil would be produced.

Base Case Sensitivities:

While a conservative approach was used throughout the Base Case estimate, no economic analysis would be complete without testing the sensitivities of various critical items.



As the project is somewhat capital intensive, project economics exhibit a relatively high degree of sensitivity to changes in capital costs, particularly as costs decrease. A 50% decrease in capital costs would more than double the rate of return from 39.5% to 83%, while a 50% increase would only decrease it to 20%.

Interestingly enough, the level of operating costs required by a gravity oil project is such that even large changes in either direction pose little potential impact. In effect, this opportune relationship would allow increased production through additional drilling at extremely favorable rates of return.

As might be expected, project economics are quite sensitive to price. However, a 30% reduction would still yield a return of 22%, while any increase would serve to enhance the economics of the project.

The production sensitivity profile is very similar to the price sensitivity curve. However, since the production estimates utilized a conservative approach to the Muskat Gravity Drainage equation, an increase in production or total recovery is much more likely than a decrease for a properly sited project. Nevertheless, a reasonable AARR (21%) could still be achieved if a 30% reduction in production were experienced.

From a risk standpoint, exposure to failure is virtually limited to the area of initial reservoir selection. In effect, if a reasonable program of core drilling and reservoir evaluation is carried out in advance, there should be no surprises. Even here, drainage and economic models indicate that substantial production shortfalls should be overcome by the relatively inexpensive process of closer spaced drilling.

What we seem to be looking at is a relatively risk free opportunity to open the spigots on vast quantities of presently unrecoverable domestic crude.

GRAVITY OIL RECOVE
PHILLIPS
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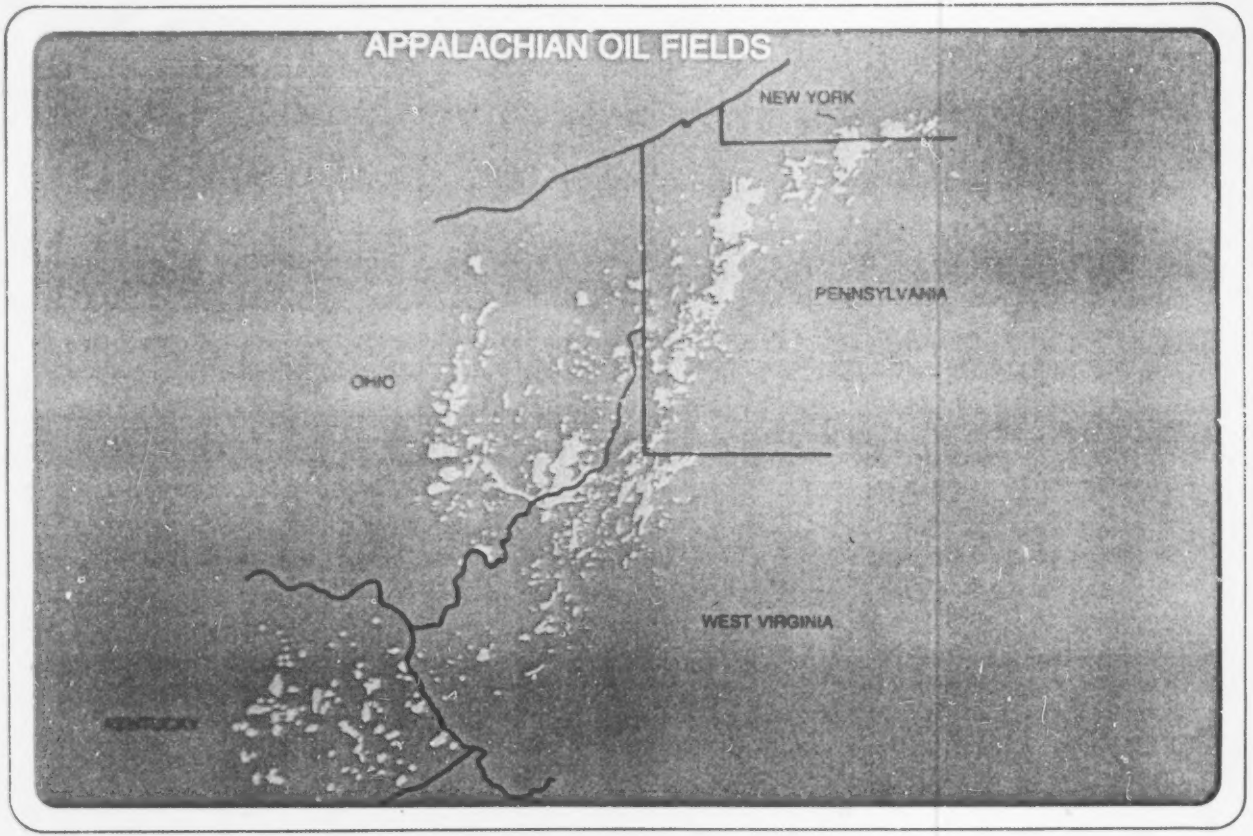
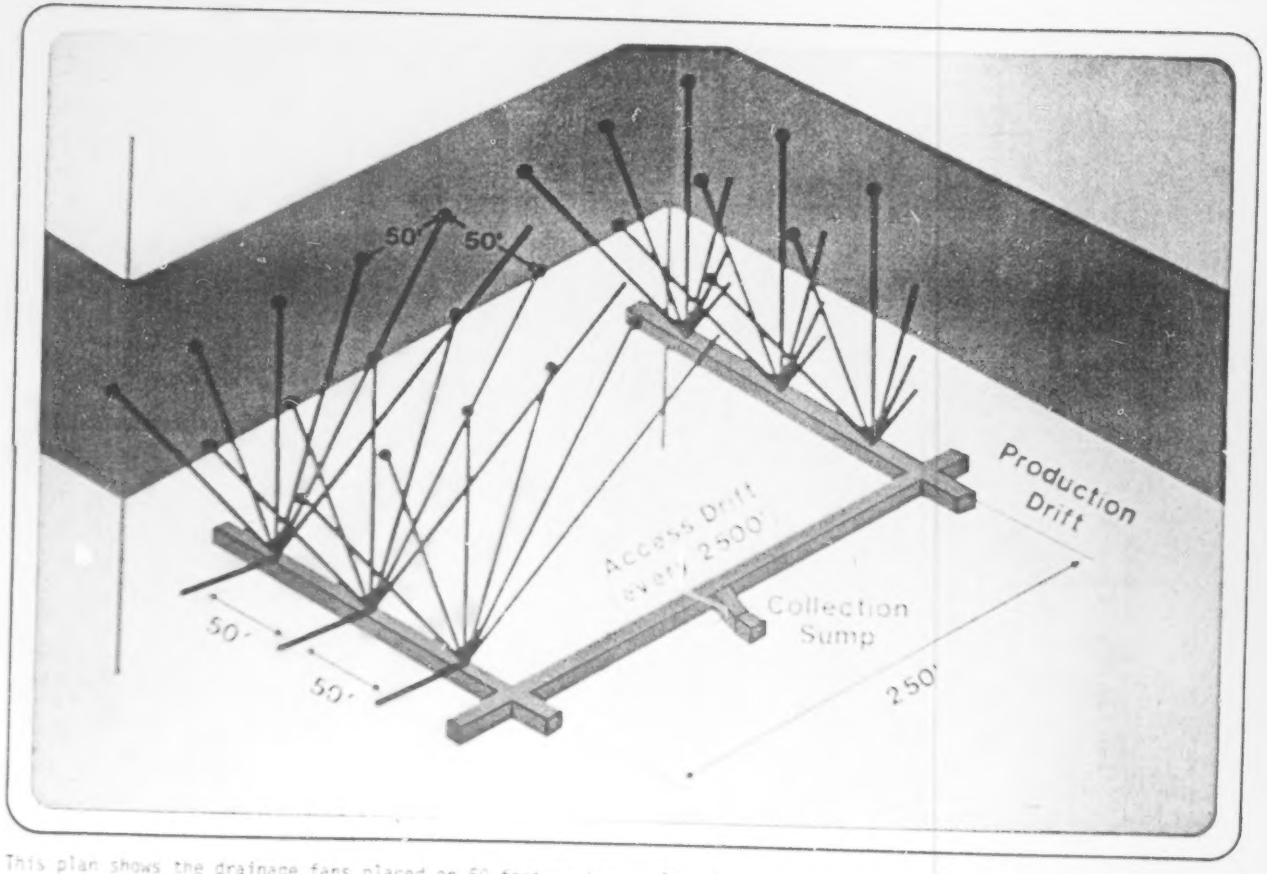
PROJECT OVERVIEW

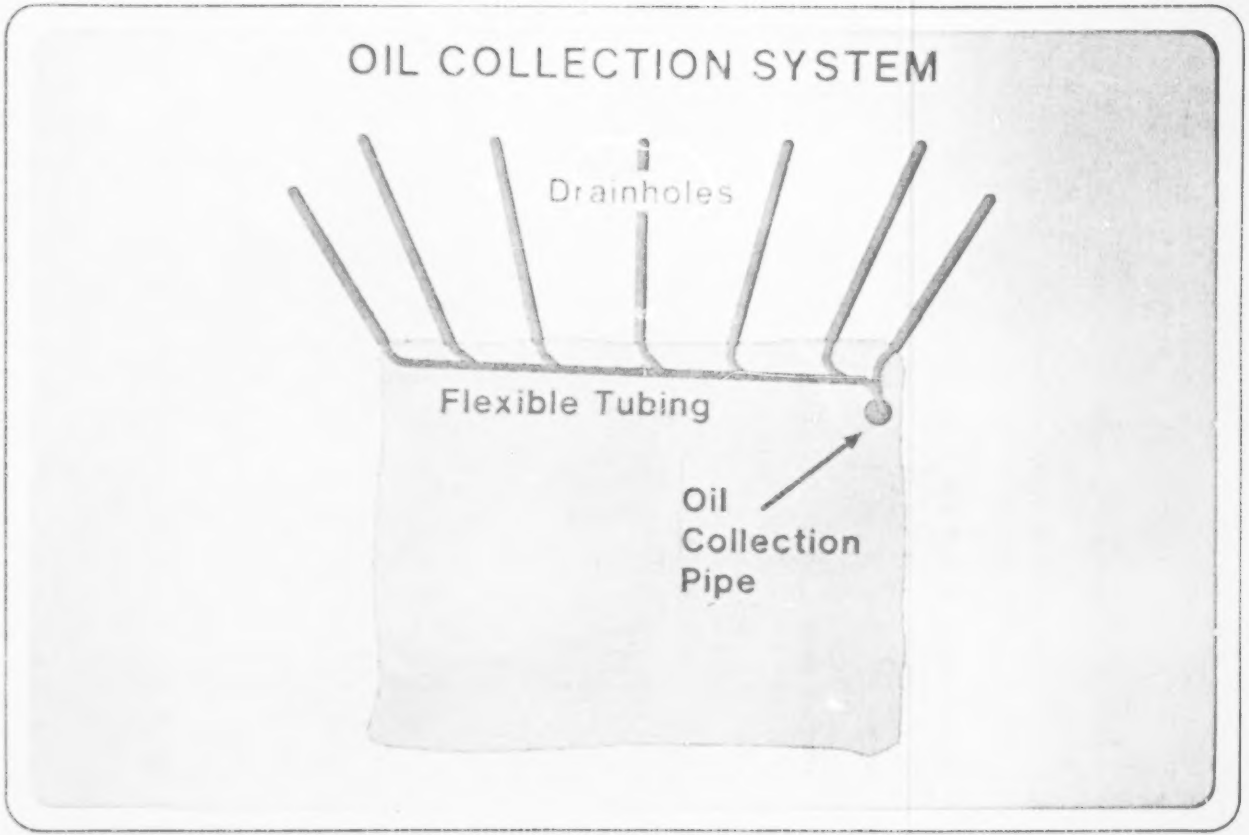
Phillips' initial survey shows a potential for Gravity Oil Recovery in at least 15 states. This limitation being largely self imposed by the more optimum conditions established for a low risk initial project.



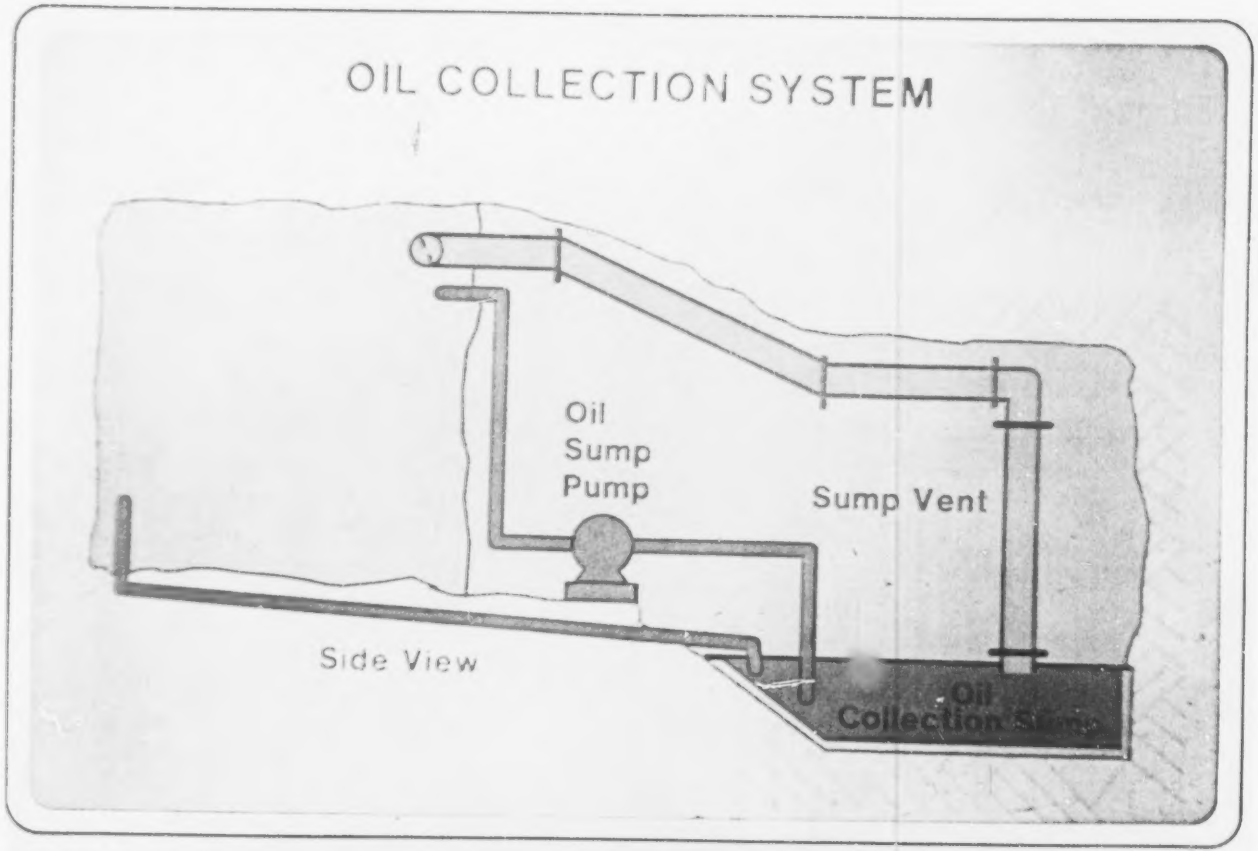
The Appalachian area holds particular promise with respect to Gravity Oil Recovery because of the numerous shallow fields, the high quality oil, and the fact many early efforts utilized inefficient recovery methods which left up to 90% of the original resource in place.



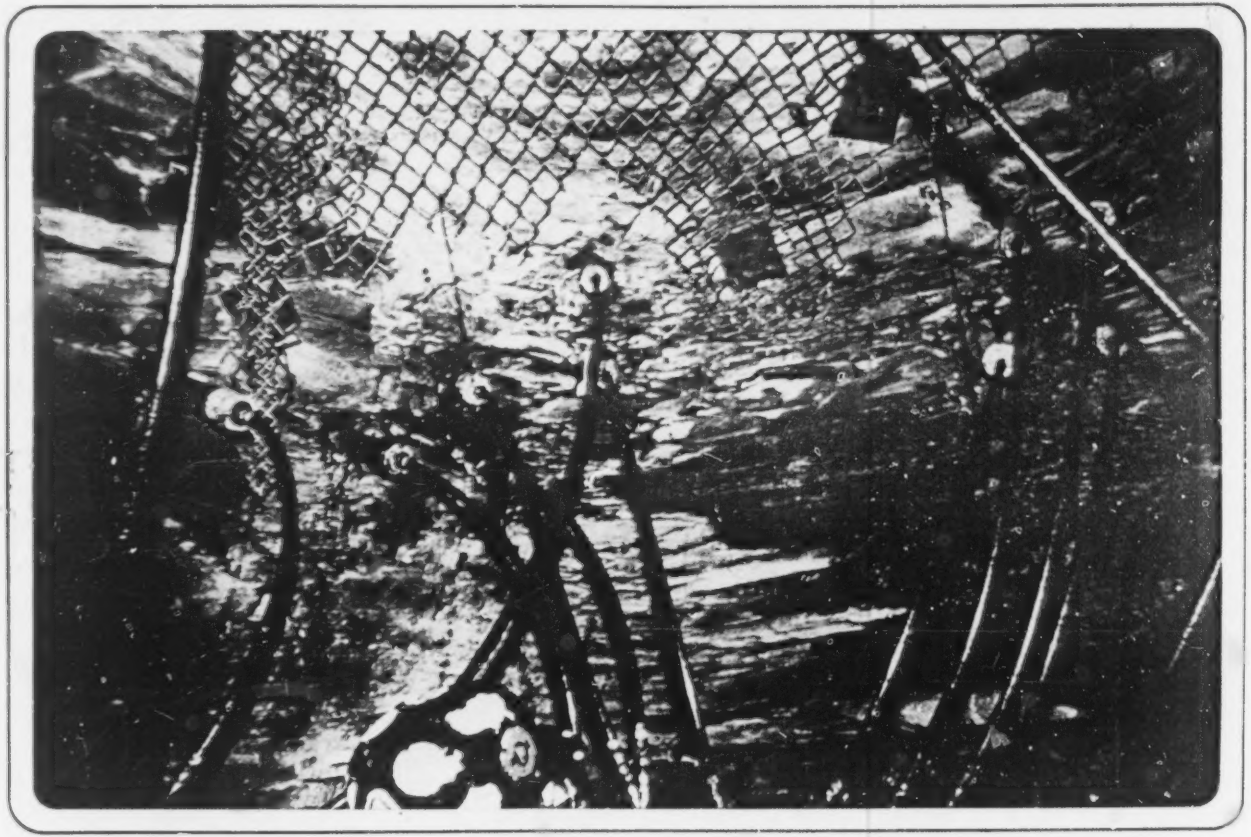
This plan shows the drainage fans placed on 50 foot centers. Actual spacing for a given oil field would be dependent on reservoir characteristics and the drainage rate necessary to suit economic requirements. The production drifts shown are 2,500 feet long, and 250 feet apart with provision for access at each end.



This is an end view of a production drift. The drainage holes drilled upward 100-200 feet, depending on the thickness of the reservoir, the depth of the production drift beneath the reservoir, and the required angle of each hole. The lower few feet of hole will be cased to provide safety during drilling, and as a means of controlling the flow of fluids during production.



This is a side view of a collection sump. While covered construction will be utilized throughout, the sump will be kept under negative pressure through an exhaust system vented to the nearest exhaust shaft.



This photograph was taken in 1982 at the New Tech oil mining operation in Ohio. The hoses shown conduct oil from the cased holes to a pipeline leading to an underground sump.

3000 BOPD DEVELOPMENT SCHEDULE
MONTHS
0
10
20
30
40
50
60
LAND ACQUISITION
DRILL & EVALUATE
AFD/AFE
ENGINEERING
SINK SHAFTS
SURFACE PLANT
DEVELOPMENT
PRODUCTION

EARL C. HERKENHOFF
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TELEPHONE (415) 376-0591

MINERAL DRESSING A SPECIALTY

February 13, 1984

Mr. Robert Terrell
Subcommittee on Energy and Natural
Resources, U. S. Senate Committee on
Energy and Natural Resources
Washington, D. C. 20510

Ref: Letter from the Honorable
John W. Warner dated Jan. 26,
1984 -- Subject: Oil Mining

Dear Mr. Terrell:

In accordance with our telephone conversation of today, I am submitting the attached technical papers on the subject of oil mining, all of which is in lieu of presenting testimony before your Subcommittee.

There are two papers: (1)"When Are We Going to Mine Oil?" published in Engineering and Mining Journal, June, 1972 and (2) "Mining--A Means to Increase Recovery of Oil-in-Place," published by courtesy of A. G. McKee Corp. in 1976.

My views as expressed in these papers remain unchanged. Moreover, the economics have been greatly improved by the current crude oil prices which are nearly 10 times higher than in 1971-1972 and 2 to 3 times higher than in 1976.

It is significant that out of some 20 major mining companies and oil companies to which were sent the McKee paper, only two indicated mild interest; none pursued the idea aggressively. In my opinion, the greatest obstacle to the advancement of mining oil is the complacency of the oil companies. They own the deposits and exhibit no desires to consider mining, either on their own part or in a joint venture with a mining company.

Mr. Terrell

Finally, my considered opinion that oil mining offers better economics and incentives than the mining of oil shales, first expressed in 1972 (page 138 of the E & M J article) and again in 1976 on page 44, still stands.

Thanking you for the opportunity to present the attached documents to your Subcommittee, I remain

Sincerely yours,

Earl C. Herkenhoff

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Attachments: (2)

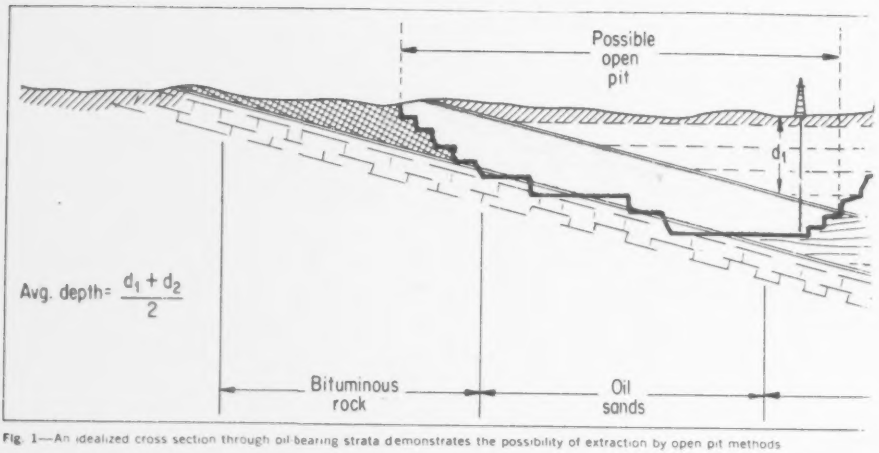


Fig. 1—An idealized cross section through oil-bearing strata demonstrates the possibility of extraction by open pit methods

When are we going to mine oil?

Earl C. Herkenhoff

MINING THE 383 KNOWN SHALLOW OIL FIELDS in the US is a practical way to increase oil production to meet the growing US energy crisis. These oil fields are merely down-dip extensions of bituminous rock deposits, actually outcropping. They have an average depth of less than 500 ft. With such deposits, the stripping ratio and the cost of exposing and mining the oil-bearing strata would be low. An idealized section through a bituminous rock deposit and shallow oil field is shown in Fig. 1.

Hard rock miners and oil producers have probably not given much thought to "mining" oil, but in recent years, several important developments have brought the economic exploitation of shallow oil fields within our reach:

1) Availability of proven, large capacity mining, hauling, and processing equipment.

2) Increasing difficulty and expense in finding more oil, coupled with increasing dependence on oil imports from countries subject to political upsets.

3) Action by OPEC (Organization of Petroleum Exporting Countries) members to increase royalties and the price of crude oil.

4) Steady progress by Great Canadian Oil Sands in the mining of tar sands in Athabasca.

Most people are unaware that recovery of oil from a pool by ordinary wells is surprisingly low—in the case of viscous heavy petroleum deposits, the recovery by wells usually is only 10-15%. That obviously means a loss of 85-90% of the oil that's down there. Oil course, oil companies have spent a great deal of money trying to develop special schemes for recovering more oil from such deposits. These schemes include water flooding, fire flooding, steaming, use of low viscosity solvents, and many other methods. However, no matter how successful these specialized schemes may be, they rarely extract more than half the oil in the formation—and often with little or no profit.

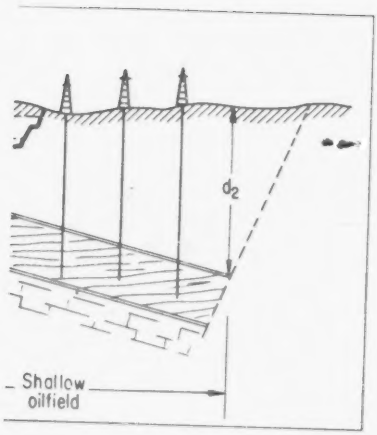
It would thus be highly significant if we could recover 95% of the oil in a reservoir. The tools are in our hands today to do this—backed up by a powerful motive. The US is facing an energy crisis and must have more oil production (see box). Why not look at mining of shallow oil fields?

How shallow oil fields differ from oil shale

How does an open-pit scheme for mining shallow oil fields compare with mining oil shales? In recent years there has been a concerted effort on the part of a number of major oil and mining companies to develop a commercial method for recovering oil from oil shale, but such methods all must contend with a serious common problem. Most oil shale must be mined by costly underground mining methods and, moreover, it must be subjected to intense heat to distill off the kerogen, or shale oil it contains. What is then obtained is not true petroleum but must be hydrogenated to make it fluid at ordinary temperatures and amenable to modified refinery processing.

All these difficulties conspire to increase the cost of the end product and leave little or no profit. Not to be overlooked is the matter of taxes and depletion allowances. Petroleum is given a 23% depletion allowance whereas mining may receive only 12.5%. It is obvious that production of a true petroleum, even if by "mining," is entitled to the 23% depletion allowance.

The other cruel fact which confronts the shale oil



processors is the location of the major deposits—in Colorado and Utah, miles from large cities (labor supply), from refineries and markets, and in a water-short area. Anyone contemplating an oil shale venture must thus provide housing, power, water, refineries, and product pipelines, in addition to the expensive underground mining facilities and high-cost shale oil extraction plants.

Contrast the above situation with some of the shallow oil fields in California. In the case of the Kern River field, for example, there is an abundant labor supply in nearby Bakersfield and surrounding communities, a high-voltage Southern California Edison power line passes overhead, a refinery already handling the heavy crude oil is nearby, and a market for the products is on all sides. Last but not least, the climate is mild—severe winter weather such as is experienced by the Athabasca tar sand miners is no problem. Later, it will be shown what a drastic reduction in capital costs results when the townsite, power house, refinery, and pipeline are eliminated from the project costs.

Past experiments

The concept of mining petroleum is not new, but it has been years since a determined effort has been made in the US to treat bituminous rocks for their oil content. To the writer's knowledge, no one has yet tackled* the mining of shallow oil fields.

The literature contains some valuable data on utilizing bituminous rocks, which are closely related to actual oil reservoir materials. The California Division of Mines and Geology paper on "Bituminous Rocks in California," April 1962, refers to early attempts to treat such deposits in Santa Barbara and Santa Cruz Counties. Shell Oil, which holds the Edna Deposit in San Luis Obispo County, operated a 200-tpd pilot recovery plant on a nearby deposit (Sisquoc) in 1958. Material treated was from a sandstone bed averaging 15 ft in thickness with 70 ft maximum of overburden. High grade asphaltic rock contained 30 gal per ton.

To stress the differences in composition and origin of various petroleum hydrocarbons, the following is quoted from the article, "Asphalt and Bituminous Rock," by C. W. Jennings (Calif. Bulletin 176):

> Native asphalt consists of heavy liquid, semi-solid, and solid hydrocarbon residues which have been deposited in surface and near-surface rocks and soil. Such deposits occur where liquid petroleum has migrated upward and lost its lighter fractions by evaporation. This process results in various types of accumulations of bituminous material, ranging from seeps and pools of almost pure heavy petroleum to rock in which petroleum residue fills a fraction of the pore space. Such terms as "tar sand," "oil shale," and "asphalt rock" are included in the more general term "bituminous rock," which refers to any rock that carries a substantial amount of petroleum. This so-called "oil-shale" in California contains hydrocarbons in the form of natural petroleum, but elsewhere as near Rifle, Colo., the term "oil shale" commonly refers to rock that contains a carbon compound known as kerogen, which is not petroleum but which can be processed to yield petroleum products. "Petroleum asphalt" is the term applied to the material manufactured at petroleum refineries by distillation. Petroleum asphalt production in the US now far outranks bituminous rock production.

In a listing of the major tar sand deposits in the US, the US Bureau of Mines (USBM) estimates the gross oil or bitumen in place for four deposits in Utah at 6,750 million bbl. Seven other smaller deposits in California, Kentucky, and New Mexico were estimated to contain 380 million bbl.

USBM has divided tar sands into roughly three broad classifications: 1) surface asphaltic deposits with very high viscosities (GCOS in Alberta, Canada, is of this type); 2) shallow deposits with thick sections, highly saturated with viscous oils; and 3) relatively deep viscous oil reservoirs. It is proposed here that Class 2 deposits should be mined.

Definition of best targets for oil mining

A shallow oil field ideal for open-pit mining will have the following characteristics:

1) It is a down-dip extension of an outcropping bituminous rock deposit, which contains at least 250 million bbl of oil in place.

2) It is covered with a soft overburden rock not exceeding the thickness of the oil-bearing formation, thus giving a strip ratio of 1:1 or less, and is amenable to low removal costs (drilling and blasting not required).

3) It is surrounded by adequate open space suitable for disposal of overburden stripping and sand tailings.

4) It contains an oil-bearing formation that:
a) is sandy rather than silty.
b) contains about 1 bbl or 42 gal of oil per ton.
c) contains oil of a low sulphur content and + 15° API gravity.
d) is sufficiently drilled by wells to define the size and attitude of the formation or "orebody."

5) It is located within reasonable distance of a crude oil collection network or petroleum refinery, and near a town or city for labor supply.

*Spencer, Eckard, and Johnson, "A Review of Potential Tar Sand Oil Recovery Methods," December 1969.

Profile of the US energy crisis*

April 5, 1971 — "Reserves in the Lower 48 fell 348 million bbl. Apart from Alaska, secondary recovery was the main factor influencing reserves in 1970."

May 10, 1971 — "US crude prices may hit $4.50 per bbl in 1980." [For E/MJ readers who are not familiar with oil prices, the current quote fob East Texas Oilfield—largest US producing field—is $3.60 per bbl.]

June 21, 1971 — "In a world where OPEC [the Organization of Petroleum Exporting Countries] has imposed its tight grip on oil supply, the American people have one choice: develop their reserves or lose their security of supply to foreign powers."

"US demand for crude by 1980 will be 25 million bbl per day, of which only 12.5 million bbl per day will be produced domestically."

July 19,1971 — "US at critical crossroads on energy policy. Interior Secretary Rogers C. B. Morton states: 'The foreign exporting nations have the will and the competence to deny dependent consuming nations their oil if it suits them . . . The decision we must make in its barest, most direct terms is whether or not we wish to accept the risks of being dependent for an expanding portion of our energy supply upon sources over which we have little or no control—or whether we are willing to support the investments in exploration, development, production, manufacture, and transportation necessary to increase our domestic energy supplies.'"

*Quotations here are excerpts from the Oil and Gas Journal.

Additional desirable features include: title to the surface and minerals preferably consolidated in a single holding; freedom from high inflow of ground water; ample supply of low cost electrical power from an existing grid; and no hazard from high pressure gas pockets.

Oil content is all-important

It should be stressed that the oil content of the oil-bearing formation in place is all-important, and should be as high as possible and probably not less than 3-4 bbl per ton. This content, and the subsequent processing recovery, sets the value of the crude ore.

To evaluate relative oil content, the following facts concerning tar sands, bituminous rocks, oil shales, and shallow oil sands are pertinent:

1) The Athabasca tar sands contain an average of 27 gal per ton recoverable oil, or about 33-34 gal per ton in place. Highest contents are reported at 18% by weight, or 48 gal per ton.

2) Colorado oil shales contain 28 gal per ton on the average; some strata of limited tonnage contain greater quantities.

3) California bituminous sands can contain up to 80 gal per ton but probably average 30-35 gal per ton.

4) Available data on US Midwest shallow oil sands indicate only 20 gal per ton.

5) The actual oil content of shallow, heavy crude fields is presently indefinite but should be higher than that of a bituminous sand because the formation actually oozes some oil into wells.

Generally, with oil dependent on porosity of the sand, there are three substances which can fill the pores: oil, water, and gas. The most attractive shallow oil sand would have a high porosity — say, 35% by volume — and low water content (gas content usually is quite low or non-existent) and would therefore contain a maximum of oil.

Although the Kansas-Missouri-Oklahoma area contains very extensive heavy oil deposits, the porosity of the sands appears to range only from 18% to 25%, thus limiting the oil content.

Figs. 2 and 3, respectively, show: 1) the relationships between oil content for both 10° and 20° API heavy oil; and 2) areas of deposit required to provide reserves of 250 million bbl of oil in sands of varying thickness and oil content.

Most prospecting for oil has been done with the object of finding an oil sand which will yield oil by pumping or — as a last resort — by fire and water flooding or steaming. Deposits of this type must have permeable sands. For winning oil by mining, however, it is likely that there are some deposits of high oil content but with very low permeability. These have been shunned in the past — for example, saturated diatomaceous earth deposits. Deposits of this type might make attractive mining targets.

Possible upgrading and selective mining

Within any given shallow heavy oil field, there will be variations in oil content within the oil-bearing formation, depending upon the type of sand or rock which encloses the oil. For example, in the Athabasca tar sands, there are at least three types of material:

	% Oil
Good grade sand	13.6
Imbedded oil sand and shale	7.0
Shale	2.0

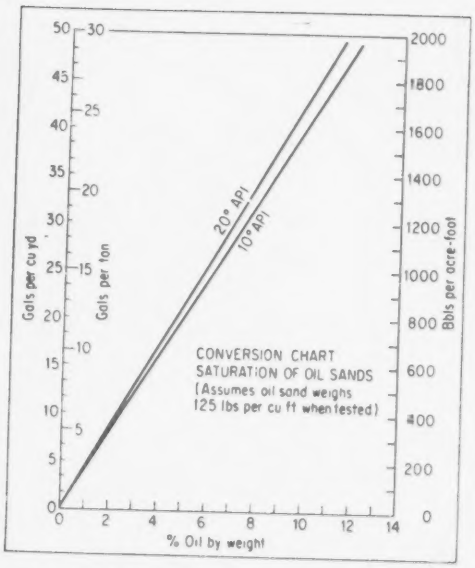


Fig. 2—Oil content for 10° and 20° API heavy oil.

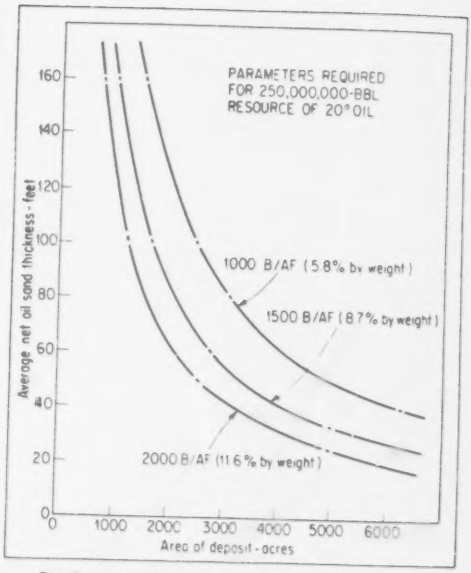

PARAMETERS REQUIRED
FOR 250,000,000-BBL
RESOURCE OF 20° OIL
Average net oil sand thickness - feet
1000 B/AF (5.8% by weight)
1500 B/AF (8.7% by weight)
2000 B/AF (11.6% by weight)
Area of deposit - acres

Fig. 3—Areas required for 250 million-bbl reserve.

The literature does not mention any attempts to upgrade run-of-quarry bituminous rock or tar sands but remarks in USBM publications R. I. 4871 and 4246 indicate that simple screening to reject lean sandy fines might upgrade the bitumen content substantially in certain deposits.

Because of the present marginal value of the oil sand, it is unlikely that more costly selective mining of higher oil-content material could be justified. This possibility would depend, however, on any particular deposit, and should not be overlooked.

Hot water processes for oil recovery

The USBM's pioneer work in 1948 used a simple flow sheet in a laboratory-scale hot water process for treating bituminous rocks. A generalized flow sheet of the process is shown in Fig. 4.

In US patent No. 3,401,100 issued in September 1968, Paul H. Floyd et al described a hot water process which apparently was the basic scheme adopted by Great Canadian Oil Sands at its Alberta, Canada, operation (Fig. 5). No solvent is required in the zones where oil is separated from sands.

It should also be noted that no appreciable amount of work is required to crush the tar sand feed, nor is grinding required (these are the big capital and operating cost items in a conventional hard rock mining operation). Separation of oil from the sands is rapid, positive, and achieved in high capacity equipment. Oil recoveries of 90-95% are reported with these processes.

Value of crude ore

The value of heavy oil in a given shallow field will depend on a number of factors but probably is most affected by gravity or °API, and sulphur content. Shown below is a price schedule recently posted for a type of California crude oil in the field:

Density, °API	Price per bbl
10-13	$2.05
13-16	2.22
16-19	2.43
19-23	2.63
23-25	2.82
25-28	3.02
28-31	3.21

Thus, with an oil content of say, 1 bbl per ton, the crude ore value of a shallow oil field would range from $2.10 to $2.75 per ton. With present day emphasis on low sulphur content, a heavy crude with low sulphur content might command a premium of $0.25 to $0.50 per bbl.

Hazards of mining oil

Probably the greatest hazard in mining an oil field is from fire, but it is believed that most heavy crudes have too high an ignition point to be considered dangerous. With open-pit operations, dangers from gas pockets would be largely eliminated.

It is apparent that with current heated opposition by environmentalists to any sort of open-pit mining, there will be objections to mining certain oil fields. However, the creation of an open-pit oil mine and a tailings basin would be no different than many present day base metal and phosphate rock mining operations.

Specific targets

Are there actually any shallow oil fields which have the characteristics best suited for mining?

Monograph 12 published by USBM (1965), "Surface and Shallow Oil-Impregnated Rocks and Shallow Oil

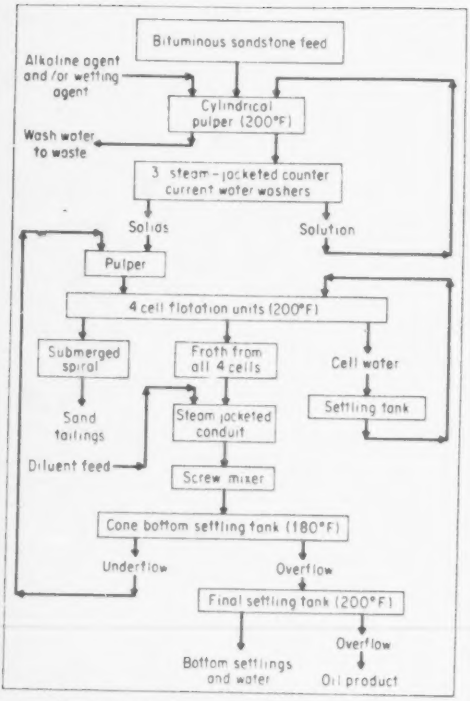


Fig. 4—USBM hot water extraction process.

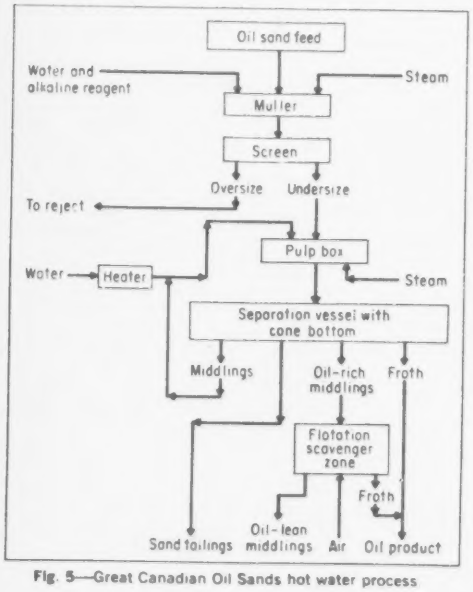


Fig. 5—Great Canadian Oil Sands hot water process.

Fields in the US." contains valuable data pertinent to the problem of mining oil sands.

For example, as listed in Table 1, there are a number of shallow fields in Texas and California with varying average thicknesses of overburden and oil-formation from which rough stripping ratios can be estimated. Several of these fields already have produced over 100 million bbl, which means 800 million to 900 million bbl remain locked in the formation below.

In California alone there are five deposits which deserve serious attention:

Kern River oil field, located five miles north of Bakersfield along the Kern River. Cumulative production to 1960 was 347.3 million bbl of 13° API oil. Total wells drilled are 4,576. The oil sand outcrops at the eastern edge and dips westward at about 5°. Total thickness of the oil producing zone is 700 ft, and "average depth" of the field is 900 ft. Proved acreage is about 9,000. If only 20% of the reserves have been recovered to date, the oil remaining in the ground is over 1,400 million bbl, a very worthy target for mining.

Principal holders of the area are Shell, Getty, and Standard of California, which holds a major portion over the indicated thickest oil formation near the eastern outcrop. Field production to July 1969 was 2,247,000 bbl, with Getty's portion as 1,487,000 bbl. Average yield per producing well was only 16.6 bbl per day, even under steam stimulus.

Edna oil field and bituminous rock deposits (San Luis Obispo County). This field is located about 6 mi east of Shell Beach, or 3 mi northeast of Pismo Beach, and is the outcrop area of the Edna oil field.

Cumulative production to 1961 was 2,219,000 bbl of 15° API oil. Total wells drilled were 122 and average depth was 750 ft, with 300 ft average thickness of producing "Dollie" sand zone. Large tonnages of bituminous sandstone outcrop in the area. Some outcrops are 2,000 ft long; one hill is about 1,000 ft square. There are two such "tar sand" beds overlying the deeper Dollie oil sand, offering an attractive strip ratio for open pitting.

Signal Oil & Gas is the prominent holder of the oil field and bituminous rock deposits.

As an additional item of interest to miners, the USBM survey for uranium content in petroliferous rocks showed the Edna tar sands to be the highest carrier tested; based on the seven samples analyzed, uranium occurred mostly in the ash from the oil.

Casmalia Oil Field. The oil field is located 3 mi southeast of Orcutt and 12 mi southwest of Santa Maria in Santa Barbara County. It is about 4 mi from the ocean.

Cumulative production to 1961 was 20,721,000 bbl of 10° API oil. There are several producing zones with thicknesses ranging from 75 to 700 ft, at an average depth of 700 to 1,400 ft. Total wells drilled were 188. Union Oil is the major holder, with some blocks by Getty and Standard of California. Sulphur in Casmalia crude is reported to be 3.5%.

The extensive Casmalia bituminous rock deposits were studied by the US Geological Survey in 1945; they are classified as "oil impregnated diatomaceous rocks" of the Sisquoc (Miocene-Pliocene) series, having a thickness of 150 to 3,000 ft.

There have been two operations on the bituminous rocks: the NTU mine, which closed down in 1928, and the "Airox" operation of Pozzolan Products, Inc. of Los Angeles, some 5 mi to the south. Airox was mining the oil impregnated diatomaceous earth, burning it in open heaps, and then marketing the cinders for light-weight aggregate

or, if finely ground, as possolans. Paradoxically, no attempt was being made to utilize the hydrocarbon content.

South of the NTU mine there is an area about 1,500 ft square which was logged by USBM as "burned shale," under which is presumed to be the oil impregnated diatomaceous rocks. A drill hole near this area indicated an average oil content of 65 gal per ton to a depth of 600 ft.

Belridge South oil field. This certainly is a prospective open-pit operation. It is located in Kern County, 12 mi northwest of McKittrick, alongside State Highway 33, on the western edge of the valley.

Cumulative production to 1960 was 81,046,000 bbl of 12°-15° API oil. The shallowest producing zones are the Tulare sands, which have a thickness of 400 ft and an average depth of 400 ft. Total wells drilled are 1,751, over an area of 8,000 acres (an anticline 8 mi long and 2 mi wide). Oil remaining in the ground probably exceeds 325 million bbl.

Belridge Oil, the operator, is one of the small old oil companies (first well in 1911). The sulphur content of Belridge crude apparently varies from 0.25% to 1.6% S.

McKittrick Oil Field. Two mi west of the town of McKittrick in Kern County is the McKittrick field. Like Belridge, it is a shallow anticline about 4 mi long and 1 mi wide. Cumulative production to 1960 was 105.6 million bbl of 12°-18° API oil. Average depth is reported as 500 ft, with 300 ft of producing formation, developed by 584 wells, but oil is found at the surface in places. It is estimated that 420 million bbl of oil remain.

Heavy oil was "mined" from open pits and shafts as early as 1861. Oil was obtained from numerous shallow wells drilled later; hence it is probable that considerable oil could be recovered from near-surface material. The sulphur content appears to be about 1%.

Some

Table 1—Shallow oil fields in the US

Field	Formation	Age	Avg. depth (feet)	Thickness (feet)	Oil grav. °API	Discovery date
TEXAS						
Pamela 150	Rustler	Permian	105	93	24	1957
Fasken	—	Permian	475	110	31	1949
Regular	Strawn	Pennsy.	126	?	?	1913
Atkinson	San Angelo	Permian	390	51	22	1960
Slocum	Carrizo	Eocene	480	48	20	1955
New Sweden	Serpentine	—	483	40	34	1955
Wall Pulazy	Pulazy	Lower Cretaceous	283	37	18	1961
Chittim	San Miguel	Upper Cretaceous	48	51	16	1962
Albrecht	85' Sand	—	85	17	?	1960
CALIFORNIA						
Kreyenhagen	Temblor	Miocene	300	100	17	1929
Devils Den	Salt Creek	Miocene	200	260	19	1901
Lost Hills	Tulare	Pleistocene	200	100	12 20	1910
Welcome Valley	Tumey	Oligocene	266	100	—	1952
Belridge South	Tulare	Pleistocene	400	400	12 15	1911
Kern River	Kern River	Pleistocene	30 to 1,300	30 to 700	13	1899
NE Edison	Chanac	Mio. Pleistocene	350	120	12	1935
TipTop	Santa Margarita	Miocene	430	350	24	1918
Conejo	Volcanics	Miocene	50	250	15	1892
Dewitt Canyon	Top Moledo	Miocene	90	120	24	1882
Townsley Canyon	Modelo	Miocene	90	120	21	1893

In the above list, Belridge South and Kern River fields each had produced in excess of 100 million bbl by 1964. Lost Hills production was 83 million and NE Edison was 18 million bbl.
Source: US Bureau of Mines.

Preliminary economics for a domestic operation

Capital costs. To provide a perspective on capital costs required to undertake a tar sand mining venture, Table 2 gives data for the Cities Service proposed Athabasca tar sand project (reproduced from the Jan. 14, 1963, issue of OIL AND GAS JOURNAL).

It should be remembered that the tar sand probably contains only 27-30 gal of recoverable oil per ton, which, at an estimated value of $3.00 per bbl, makes the crude ore head value only $2.03 per ton.

Now take the above capital costs and assume that the same capacity plant could be built for a shallow oil sand yielding a "regular" petroleum of low-to-medium gravity (13° to 18° API), in a location near an established town, supplied by public power, and with an existing pipeline transportation network. It is estimated that the project cost would decrease by $150 million, to a total of $206 million vs the original $356 million — a decrease of over 42%. This brings the capital cost down to about $2,000 per daily bbl of capacity.

For a feed rate of 44,500 tpd, the capital cost is estimated at $89 million. Interest during construction has been included in the capital estimate. A plant of this capacity should produce 13.2 million bbl of oil per year.

A 1969 press release stated that Syncrude Canada Ltd. has proposed to the Alberta Oil and Gas Conservation Board that an 80,000 bbl per day plant be constructed at a cost of $195 million, or $2,400 per daily bbl of capacity. (Syncrude is owned by Atlantic Richfield, Cities Service, Imperial (Jersey), and Gulf.)

Operating Costs. Based on the information which has been studied, and on a preliminary scheme for mining an oil sand deposit, operating cost estimates have been prepared, as listed below. The operation would be designed to recover 40,000 bbl of oil per day from a plant feed containing 1 bbl of oil per ton, at a 90% recovery.

It appears reasonable to assume a stripping ratio of only 1:1 if the deposit is a down-dip extension of an oil-bearing outcrop, as illustrated in Fig. 1. Stripping and mining costs assume use of large excavator and haulage units with no requirement to drill and blast.

It was assumed that the royalty on production would be only 10¢ per bbl of recovered product. This may be low, but perhaps can be justified on the basis of a 90% recovery of the oil in place, rather than 10-15% by pumping.

No provision has been made for a refinery to crack the recovered oil, although the recovery process might require the circulation of a naphtha "thinner" to facilitate removal of fine solids from the oil. The requirement for the thinner appears to be related to the viscosity of the crude oil; with higher gravity oils, it might not be required.

It should be stressed here that the oil content of the feed is critical, and profit margins would greatly improve if a higher grade feed material were treated, since operating costs would probably not increase to any measurable degree even when treating a 60-gal-per-ton feed.

However, at this moment we have little evidence on hand that would encourage us to expect oil content of

Table 2—Costs of proposed tar sand project

Production rate: 100,000 bbl per day.
Location: Mildred Lake, Canada.
Pipeline: From site to Edmonton.

Construction costs		
1) Mining, processing, and offsites		
Mining and conveying		$ 59,500,000
Extraction, dehydration		34,900,000
Bitumen upgrading		68,900,000
Waste disposal		5,600,000
Offsites		45,100,000
Site preparation		1,800,000
2) Pipeline		28,000,000
3) Power plant		30,000,000
	Subtotal	$273,800,000
Pre-production costs		
Overburden removal		3,300,000
Paid up royalty		8,900,000
	Subtotal	$ 12,200,000
Other costs		
Initial catalyst, chemicals		$ 1,200,000
Interest during construction		31,900,000
Townsite subsidy		6,500,000
Working capital		12,000,000
Startup costs		18,400,000
	Subtotal	$ 70,000,000
	Grand total	**$356,000,000**

Capital cost per daily barrel of capacity = $3,560

Source: OIL AND GAS JOURNAL

more than 1 bbl per ton, although logic would suggest that a deposit which yielded oil by pumping might contain 15-20% more oil than would be contained in a bituminous outcrop.

a) Estimated production costs — oil sand mining project*

	$ per ton feed	$ per bbl oil recovered
Stripping (1:1 ratio)	0.15	
Mining and conveying	0.15	
Sizing and processing	0.35	
Tailings disposal	0.09	
Process water supply	0.05	
Subtotal	$0.79	
General and administrative	0.15	
Total	$0.94	$1.04

*Based on an oil content of 1 bbl (42 gal) per ton of oil sand feed, with 90% recovery in the process plant, and 15°-20° API gravity oil as product. Value of recovered oil is assumed to be $2.50 per bbl at the project site.

b) Estimated cost for oil recovery process.** For a feed rate of 44,500 tpd and a production rate of 40,000 bbl of oil per day, using a hot water flotation process, it is estimated that the "milling" costs would be:

	¢ per ton feed
1) Crushing and screening	10
2) Caustic soda 1 lb (@ 8¢	80
3) Power-flotation, 3 kwh (@ 1¢	30
4) Power-oil centrifuges, 2 kwh (@ 1¢	20
5) Wear parts and supplies	50
6) Operating labor	10
7) Maintenance labor	30
8) Steam and heated water (2 gal oil (@ 6¢)	120
Total	350***

**Conditioning with NaOH @ 70% solids, plus steam to attain 200° in pulp, flotation of the oil and centrifuging of the oil product for reduction in insoluble matter.

***It is believed that if a thermal distillation recovery method, such as the U.S. Bureau of Mines gas combustion retort, were used, the allowance of 35¢ per ton would cover costs for that type of processing.

Return on investment.

		(000$)
Annual gross revenue (@ $2.50/bbl		$33,000
Less operating cost		13,700
Less royalty (@ 10¢/bbl		1,320
		$17,980
Less depreciation[1]		5,930
Less interest[2]		3,560
	Income	$ 8,490
Less depletion[3]		1,593
		$ 6,897
Less income tax[4]		3,586
	Net income	$ 3,311
Add depreciation		5,930
Add depletion		1,593
	Cash flow	$10,834
Pay back period		8.2 years

1) Depreciation on 15-year straight line basis.
2) Depletion at 23% of gross revenue or 50% of net—whichever is lesser.
3) Interest at 8% averaged over 15-year period.
4) Income tax at 52%.

Conclusions

1) There are a number of shallow oil fields in the US from which oil could be produced by open-pit mining. A recovery of over 90% of the oil in the field is possible by mining and hot water processing.

2) Proven high capacity equipment for stripping, mining, and hauling operations is available now. Numerous hard rock mines are presently operating at tonnage levels in excess of that required for an economically viable heavy oil mining venture.

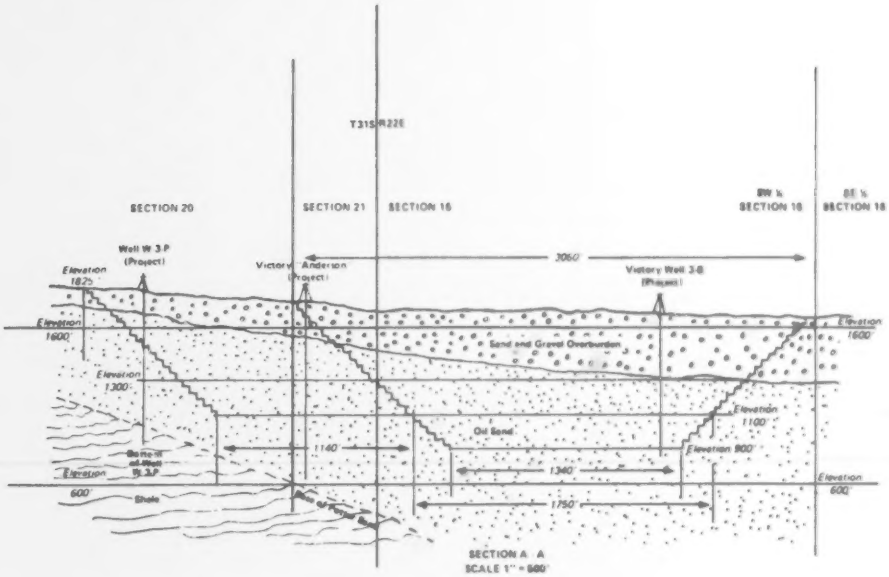
3) Preliminary cost estimates indicate that mining of shallow oil fields is marginally economic now, and will be increasingly attractive as the price of crude oil rises and as demands for greater reserves of domestically recoverable oil intensify.

4) Mining of shallow oil fields will precede the development of shale oil production because the economics are more favorable (capital and operating costs are lower) and less process development is required.

5) As with all other mining projects, objections from environmentalists can be anticipated, but reasonable pollution control standards should be attainable at acceptable cost.

6) Because of the assured increase in reserves of recoverable oil if mining were successful, the government should grant tax incentives to operators of oil mines.

MINING — A MEANS TO INCREASE RECOVERY OF OIL-IN-PLACE



by E.C. Herkenhoff

Davy McKee

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Mr. Herkenhoff has over forty years of metallurgical and mining engineering experience. He has held numerous management-level positions in which he has evaluated mineral deposits, mining ventures and processing schemes; prepared capital and operating cost estimates for projected as well as existing ore complexes; offered technical advise during exploration activities and construction and operation of mine facilities. A long time proponent for mining shallow oil deposits, he authored an article in 1972 entitled, *When Are We Going to Mine Oil?* Mr. Herkenhoff's broad expertise involves the evaluation and processing of: copper ores, iron ores, laterite nickel deposits, copper/nickel sulfides, fluorspar deposits, phosphate rock, potash-bearing brine deposits, and uranium ores. Mr. Herkenhoff was an Executive Engineer and is presently a consultant to Davy McKee Corporation.

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MINING – A MEANS TO INCREASE RECOVERY OF OIL-IN-PLACE

Introduction

Despite the widely-publicized warnings by some major oil companies as far back as 1969 and by other organizations concerned with energy, it took the icy blows of the winter of 1976-1977 to pound home the message of fuel shortages to the vast majority of the American public. Perhaps now it will be accepted that our reserves of oil and gas have steadily declined to the point where it can firmly be said "the energy binge is over". Judging from remarks frequently overheard in public places, Mr. Average Citizen has regarded the energy shortage merely as a plot so that the oil and gas companies could raise prices. Very few, it seems, realize that oil and gas deposits are finite, exhaustible and non-replaceable. And we've already discovered most of our big U.S. fields.

Now the burning question is, "How do we overcome the energy crisis?" Aside from exploring for and developing oil reserves at greater depths both on-shore and off-shore, there is another way to increase our recoverable reserves and that is, get more oil out of our proven deposits. It is almost shameful that, on the average, we are getting only about 25 to 30 percent of the oil that is contained in a deposit. In some fields it is less than 10 percent.

In contrast, in our metal mines, even those of the lowest grade, we often recover 85 to 90 percent of the resource in the form of finished metal. Strip mines in the coal fields recover from 90 to 95 percent of the coal in place. So why are we leaving so much oil in the ground? To understand the situation, we must first understand what petroleum is, where it accumulates in the earth's crust and how we presently recover it. Then we can examine ways to increase the percentage of oil that we recover from a given deposit. One important way - virtually untried in the United States - is to mine the oil-bearing rock or sand and then extract more than 90 percent of the oil therein.

The importance of increasing the quantity of recoverable oil from a given oil field can best be appreciated by some recent Federal Energy Administration statistics, namely: "If the oil recovery from each U.S. reserve were increased just one percent, about four billion barrels would be added to the available supply of crude oil". (A barrel contains 42 U.S. gallons.)

Truly, the rewards for achieving such a goal are enormous in terms of benefits to the nation's economy. The needs to produce more oil domestically are graphically emphasized by the following data from the January 14, 1977 issue of the Wall Street Journal. These data compare our country's production and imports of crude oil for two periods: (1) just before World War II, and (2) the 1970's through 1976.

U.S. Petroleum Pre-War
(Thousands of Bbls. Crude)

Year	*Production*	*Imports*
1937	1,279,160	24,484
1938	1,214,355	26,412
1939	1,264,962	33,095
1940	1,353,214	42,662
1941	1,402,228	50,606

U.S. Petroleum 1970s
(Thousands of Bbls. Crude)

Year	*Production*	*Imports*
1970	3,517,000	483,293
1971	3,454,000	613,417
1972	3,455,000	811,135
1973	3,361,000	1,183,996
1974	3,203,000	1,269,155
1975	3,060,000	1,490,000
1976	2,980,000	1,960,000

It will be noted that we are producing more oil, of course, but since 1972 at a declining rate. However, compared with pre-war demands the population, the economy, and the consumption are vastly bigger. The dependence on imports has become gigantic - and alarming. We must--and we can--take positive steps to decrease our dependency on imported oils by applying American ingenuity and technology, and offering tax incentives, to the problem of recovering more of the petroleum resources with which our country has been blessed. Therefore, let us examine how this might be done by mining techniques.

History

Few people realize that petroleum is a fluid mineral or "rock oil". The history of petroleum and its effects on mankind go back to the dawn of history. Many of the ancient peoples are known to have mined shallow petroleum deposits of oil-derived asphalt which was called "pitch". It was used for building cement, boat construction, medicines and even to preserve mummies in Egypt. Earliest use goes back to at least 4000 B.C.

Rock asphalt was mined in Europe and used for road building after the Napoleonic wars. It is sobering to recall that oil distilled from oil shale was used for street lighting in Madena, Italy late in the 17th century and a by-product of the process was paraffin for candles.

Natural gas, escaping from vents in the earth, was utilized in temples for "external fires" near Baku and around the Dead Sea. In the U.S. the first use of natural gas is thought to have been that from a shallow well at Fredonia in New York in 1820. However, in China about 250 B.C. there were records of using natural gas from shallow wells as fuel.

It was not until August, 1859 that the first true oil well was drilled in Pennsylvania and produced oil from a depth of 70 feet. This touched off the search in other parts of North America and in other countries such as Europe, Russia, Mexico, and Venezuela. But production from the Middle East fields in Saudi Arabia began only in 1938, in Iraq in 1927 and in Iran in 1908.

When the search spread from land to shallow waters offshore in the 1960's, discoveries were made which now have become very important sources to the world's supply as evidenced from Table I. The principal oil-producing countries in 1971 are listed in Table II with relevant data in Tables III and IV.

Obviously, it is most unlikely that oil will ever be mined from offshore deposits and there is less likelihood that the recovery of the oil from such deposits will exceed about 35% of the oil in place even using all the recovery technology we now have.

Origin of Petroleum

The general evidence indicates that petroleum was formed primarily from a marine animal source. On the other hand, methane gas is an important constituent of the atmospheres of the outer planets and tails of comets are composed largely of methane. It is possible, therefore, that some of our terrestrial hydrocarbons are related to the cosmic history of the earth, while most crude oil components were derived from biogenic materials.

Only a small fraction of the total marine material that has existed in the world's seas could quantitatively have produced all the petroleum that has been found to date. As these materials accumulated in the muds, clays and shale sediments of the sea floors and shores and gradually were subjected to chemical and thermal alteration, the various saturated and unsaturated hydrocarbons, paraffins, napthenes and benzoid groups were formed which are characteristic of crude oils.

Under the drive of temperature and pressure increases and rock deformation stresses, the hydrocarbons are believed to have left the sediments in which they were formed and entered the semi-porous, coarse-grained "reservoir rocks" in which they then accumulated. Subsequent crustal rock movements formed these reservoir rocks into geologic traps or oil pools which were filled by migrating crude oil.

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Table I

OFFSHORE OIL PRODUCTION 1970
(Outside USSR, East Europe and China)

	M b/d
Venezuela	2,761
USA (inc. Alaska)	1,577
Saudi Arabia and N. Zone	1,251
Iran	322
Nigeria	275
Abu Dhabi	269
Egypt (UAR)	257
Australia	216
Qatar	172
Brunei-Malaysia	146
Cabinda	96
Trinidad	76
Dubai	70
Mexico	37
Gabon	29
Peru	23
Other States	27
	7,604

Table II

PRINCIPAL OIL-PRODUCING COUNTRIES, 1971

	MM Brl	*% of total*
USA	3,478	19.9
USSR	2,701	15.5
Iran	1,657	9.5
Saudi Arabia	1,642	9.4
Venezuela	1,295	7.4
Kuwait	1,068	6.1
Libya	996	5.7
Iraq	622	3.6
Nigeria	556	3.2
Canada	483	2.8
Indonesia	326	1.9
11 leading countries	14,824	84.8
50 other countries	2,657	15.2
World Total	17,481	100.0

Table III

CRUDE OIL PRODUCTION OF MAJOR AREAS, 1971

	MM brl	*% of total*
Middle East	5,929.3	33.9
USA	3,478.1	19.9
USSR	2,701.0	15.5
Africa (North and West)	2,065.0	11.8
South America and Trinidad	1,689.1	9.7
Rest of the World	1,618.9	9.2
World Total	17,481.4	100.0

Source of data: World Oil, October, 1972.

Table IV

CHANGING PROPORTIONS OF WORLD OIL OUTPUT, 1946-1971

	1946[1] %	*1971*[2] %
United States	63.2	19.9
USSR	5.9	15.5
Middle East	8.9	33.9
Venezuela	14.1	7.4
Rest of World	7.9	23.3
	100.0	100.0

1 World output 2.75 B brl
2 World output 17.5 B brl

Source of data: E.N. Tiratsoo - "Oil Fields of the World."

Reservoir rocks must have the essential properties of porosity and permeability. Porosity is the ratio of all interconnected pores or open spaces to the overall volume of the rock mass. This porosity factor controls the volume of the fluid or gas that can be contained in a unit of rock. Good reservoir rocks have porosities from 30 to 40%. Permeability is the measure of the capacity of the rock to transmit its fluid or gas content.

Ordinarily, there are 3 things which can occupy the pore space in an oil reservoir rock: (1) crude oil, (2) gas and (3) water. Obviously, a high crude oil and gas content is desirable whereas a high water content is undesirable and seriously reduces the overall oil content of a given reservoir.

The most important types of reservoir rocks are sandstones and carbonates in sedimentary-type rocks.

Oil exploration work is aimed primarily at finding reservoir rocks and the stratigraphic traps that could result in oil accumulations.

Crude Oil

The American Petroleum Institute defines crude oil as "a mixture of hydrocarbons that exists in the liquid phase in natural underground reservoirs and remains liquid at atmospheric pressure after passing through surface separating facilities". Most crude oils are yellowish-brown to black in color, with a characteristic greenish reflection by reflected light. They are generally lighter than water.

The principal components are hydrocarbons but there are other chemical elements present. Table V shows the most important elements present in normal crude oils.

Table V

	% Weight
Carbon	84-87
Hydrogen	11-14
Sulfur	0.6-2.5
Nitrogen	0.6-2.0
Oxygen	0.2-2.0

A "sweet" or "low sulfur" crude oil is one which contains less than 0.5% sulfur. "Sour" or "high sulfur" crude oils contain more sulfur and are subject to restrictions in some uses, especially in recent years where strict limits for sulfur dioxide emissions have been imposed by our government.

Natural Gas

Crude oil is always associated in the subsurface with varying proportions of a mixture of gases called "natural gas". Natural gases vary in composition but are mostly hydrocarbons. Some non-hydrocarbons are present also. An analysis of a typical natural gas is as follows:

Table VI

A.

	Hydrocarbons, % Wt.	
	"Wet Gas"	*"Dry" Gas*
Methane	84.6	96.0
Ethane	6.4	2.0
Propane	5.3	0.6
Butanes	2.6	0.3
Pentanes	0.6	0.2
Hexanes	0.4	0.1
Heptanes	0.1	0.8

B.

	Non-Hydrocarbons, Typical	*% Weight Maximum*
Carbon Dioxide	0-5	98
Helium	0-0.5	8
Hydrogen Sulfide	0-5	63
Nitrogen	0-10	86
Argon	0-0.05	--
Radon, Krypton Zenon	Traces	--

Source: E.N. Tiratsoo - "Oil Fields of the World"

Natural gas may occur as free gas filling pore spaces in certain formations or in solution in crude oil. Often it occurs as a gas cap over an oil reservoir. The gas-to-oil ratio is a measure of the amount of gas held in solution in a crude oil. It may vary from less than 100 cubic feet per barrel of oil to more than several thousand cubic feet per barrel.

Usually, it is impossible to produce crude oil from a subsurface oil reservoir without also producing the natural gas associated with it. This co-product gas may be recovered and sold or merely "flared" by burning it or venting it to the atmosphere. This wasteful practice has been common in many of the world's major oilfields.

Natural gas in the oil-bearing rocks of a reservoir is a most important factor in the recovery of the oil because the gas "drives" the liquid petroleum through the pore spaces into the production wells and influences the viscosity.

Although recovered natural gas has been used primarily as a domestic and industrial fuel, it is fast becoming more important as a chemical feedstock. For example, ammonia and acctylene along with a host of other petro-chemicals are produced from natural gas. It has been proposed that we strictly limit the use of natural gas as a general fuel and conserve it for petrochemical synthesis. Recent price trends for natural gas will probably hasten this change in use.

Structural Oil Traps

Returning to the subject of crude oil deposits and how to recover the oil from them, we must consider the subsurface structural features which form the traps for the migrating hydrocarbons.

Any mechanism which arrests the flow of hydrocarbons migrating updip within a permeable bed or stratum will tend to form an accumulation. Sometimes impermeable beds such as shales lie above and below the migration channel and if a sealing medium such as a salt mass or a plug of asphalt intersects the channel, an accumulation will form. Sometimes the oil migrates to the ground surface of an inclined permeable channel and, due to evaporation and oxidation, will form a tar sand capping that becomes impervious. This type of trap is called a "homocline" or sealed monocline. Such a trap is highly important to the recovery of the oil by surface mining.

The most common traps are the anticlines or "domes" and over 80% of the world's known accumulations have been found in anticlines. An anticline takes the form of upfolds of rock strata which are generally oval in shape. Sometimes anticlines have been subsequently deformed by faulting, erosion and warping, thus limiting oil accumulations to the flanks. Most anticlines are only a few miles long and wide.

Other common structural traps are fault traps, salt domes and buried ridges. Figures 1 through 5 illustrate sections through some idealized structural traps.

Stratigraphic Traps

Stratigraphic traps are formed when a permeable bed is bounded on one or more sides by a zone of low permeability. Included in this type of trap are carbonate reefs and sandstone lenses sometimes called "shoestring sands". The latter could be important to mining of oil because they sometimes occur near-surface, as in Kansas and Oklahoma. (See Figure 6)

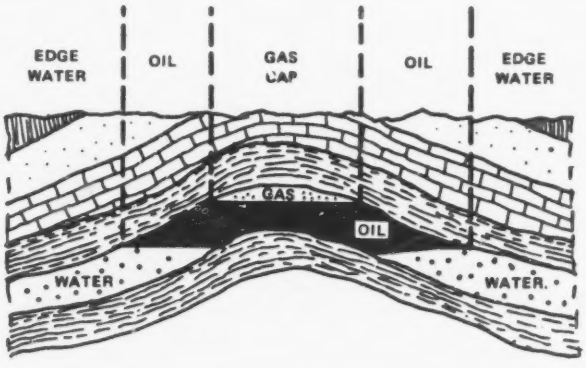

FIGURE 1
IDEALIZED CROSS-SECTION OF AN ANTICLINAL TRAP SHOWING GAS, OIL, AND WATER LAYERS

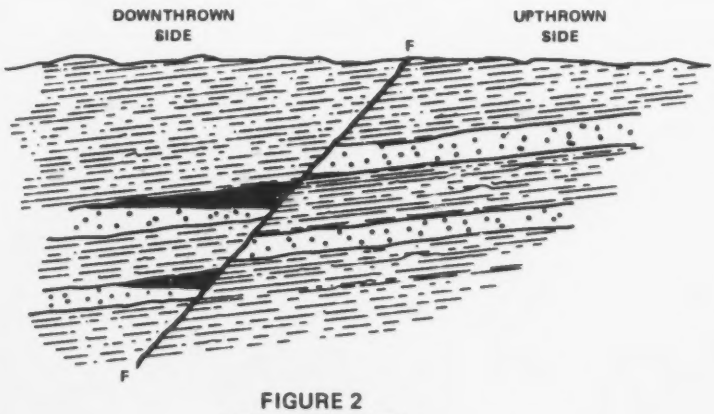

FIGURE 2
A FAULT TRAP WITH OIL IN POROUS RESERVOIR BEDS SEALED AGAINST THE FAULT PLANE

SOURCE: Tiratsoo "Oil Fields of the World"

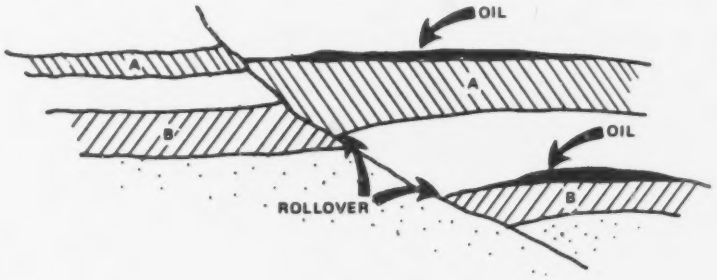

FIGURE 3
TYPICAL "GROWTH FAULT" AND "ROLLOVER" TRAPS AS FOUND IN U.S. GULF COAST FIELDS

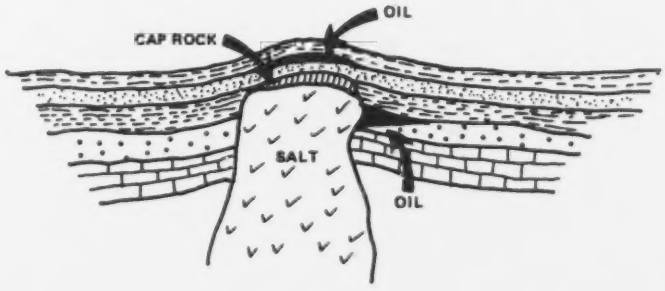

FIGURE 4
TYPICAL SALT DOME MASS INTRUDING PRE-EXISTING SEDIMENTS PRODUCING ANTICLINAL AND FLANK SEALED TRAPS

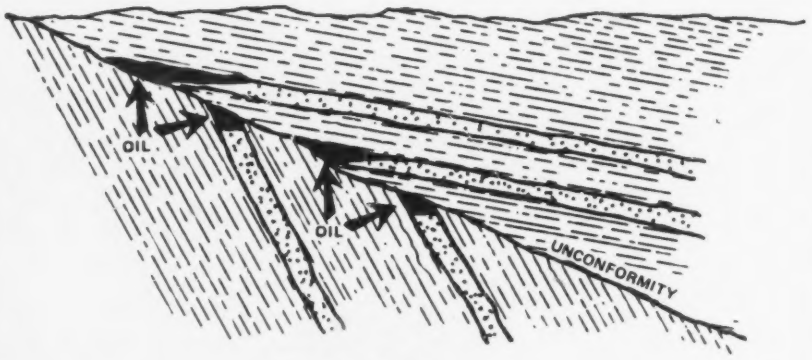

FIGURE 5
TRAPPING OF OIL IN PERMEABLE BEDS LYING ABOVE AND BELOW AN UNCONFORMITY

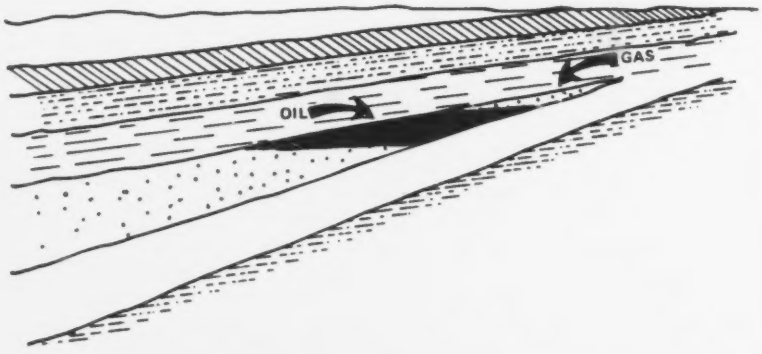

FIGURE 6
IDEALIZED STRATIGRAPHIC TRAP HYDROCARBONS IN SAND BODY WHICH PINCHES FROM LEFT TO RIGHT

Some of the most prolific oil wells on record were located on reef reservoirs. A single well in Mexico once produced 260,000 barrels per day from such an oil reservoir! An oval structure on a carbonate reef formation in Libya having dimensions of only about 2-1/2 by 3 miles is reported to have contained 2 billion barrels of oil-in-place before production began.

But prolific wells are most exceptional and today much of our oil must be laboriously sucked from wells by pumping. Production rates from such wells can be as low as 5 to 10 barrels per day. Either the lack of a "gas drive", low permeability of the reservoir rock, or high viscosity of the crude oil--or all 3 factors in combination--limits the inflow of fluid to the well opening. As a result, recovery of the oil-in-place is woefully low and the oil producers must resort to expensive "secondary" or "tertiary" methods to increase the production rate and total yield.

Production from Wells - Primary

The mixture of liquid hydrocarbons and gases that occupy the pore space voids and fracture channels in the rocks of an oil reservoir usually is under pressure. The pressure varies but normally is not less than the hydrostatic head of a water column extending to the surface. When a well drilled from the surface penetrates the reservoir, a pressure gradient exists and fluids plus dissolved gas will move from the pore spaces into the well opening and towards the surface. "Bringing in" a well requires careful operation and the pressure differential is adjusted by the weight of the drilling fluid or mud. If a high pressure reservoir is intersected and proper precautions are not taken, a "blow out" can take place, especially in exploratory wells drilled into new reservoirs with unknown characteristics. Many of us have seen photographs of certain spectacular "gushers", some of which subsequently caught fire and destroyed the drilling derrick, rig and all associated equipment.

To illustrate the conditions and problems associated with the finding of a gusher it is interesting to recall the history of a unique well in the San Joaquin valley of California in the giant Sunset-Midway field. Quoting from the book, "The Black Bonanza," a story about Union Oil Co:

"At midnight on March 15, 1910 after drilling to a depth of 2200 feet, water, shale and sand began burbling out of the well. By 8 o'clock the next morning a column of gas and oil was roaring out hundreds of feet high, drenching the entire surrounding area. For months the well, named Lake View No. 1, spouted oil completely out of control making a crater so deep the derrick and all equipment disappeared. The initial flow was estimated at 125,000 barrels per day; 30 days after the first gush, the flow was gauged by engineers at 90,000 barrels per day. After 18 months of such stupendous production the flow ceased as abruptly as it began and the hole caved in. Official estimates of the yield were 9 million barrels of 32-gravity oil." Miraculously, the well never caught fire. Most of the oil was recovered from surface ponds created by impoundment dikes.

In contrast with highly prolific wells described above, the flow of oil into a well might be slow due to low permeability of the oil-bearing formation or clogging of the rock pores by the drilling mud, high viscosity of the oil and lack of a gas drive. In such cases the yield of crude oil may be very low and the "primary" oil, the volume of oil that can be recovered at the surface by natural reservoir energy, may be less than 5 to 10% of the oil-in-place; seldomly does it exceed 30%.

Oil producers then attempt to increase the flow by creating new fractures and channels by mechanical means such as hydraulic or explosive fracturing and acid treatment. Sometimes "propping agents" are injected into the newly-formed fractures. Rounded grains of silica sand, glass beads and steel shot are types of propping agents and their function is to hold open the cracks and fissures created by fracturing.

Production from Wells - Secondary and Tertiary

When the flow of the primary oil into a well has halted or diminished to an uneconomic rate, primary recovery is considered terminated and techniques for secondary and tertiary production may be applied.

These techniques include gas reinjection and water injection or "water flooding", which are the common secondary recovery methods. After production by secondary methods has terminated, tertiary production techniques are applied. These methods include hot water and steam injection, injection of various miscible dry and liquid solvents, and controlled in-situ combustion or "fire flooding". Even electrothermic heating has been tried. The objectives are to decrease the viscosity of the oil-in-place and drive it from areas around injection wells to the production wells where it is withdrawn.

Obviously, there are great difficulties in trying to control flows of liquids and gases through multi-strata heterogenous rock formations situated hundreds to thousands of feet below surface. Channeling of flows through more permeable sections of a reservoir or along faults often "short circuits" the tertiary recovery agent and results in low recovery or complete failure to produce more oil. Moreover, there is an individuality of petroleum-bearing reservoirs; procedures which successfully increase oil production in a certain reservoir may not function at all in a different reservoir.

Also, where the oil-bearing formation is near the surface, there are limitations on the pressures that can be applied to drive the fluids laterally; the injected agent may prefer to migrate or flow vertically because of the greater pressure differential.

Summarizing, generally the recovery of the oil-in-place using secondary and tertiary production methods will range from a low of 5 to 10% for viscous heavy crude oils to a maximum of 40 to 50% with the less viscous crudes. Under near-ideal conditions, overall recoveries of up to 60% are sometimes reported. However, it is generally accepted that primary recoveries will average only 25% and that even with all our highly sophisticated secondary and tertiary recovery schemes, the overall recovery probably does not exceed an average of about 32% of the oil-in-place.

Shallow Oil Fields

Few people realize that over 380 oil fields in the U.S. are situated at an average depth of less than 500 feet below surface. Many such oil fields are homoclines and actually extend to the surface where the oil-bearing stratum is altered by oxidation and seepage to form a "brea" or tar sand outcrop. Deposits of this type offer prime targets for mining.

The most famous tar sands are those in Athabasca, Canada where a huge belt of viscous oil-soaked sandstone extends over an area of some 19,000 square miles and which contain an estimated 625 billion barrels of heavy, high-sulfur crude oil. Another large tar sand deposit is located in eastern Venezuela where a "tar belt" covers an area of about 9000 square miles. Estimated reserves in this belt are 200 billion barrels of heavy oil. Other tar sands occur in western Malagasy, on Melville Island in the Canadian Arctic, in Europe, Russia and in the U.S. in Utah, Kentucky and California.

Shallow oil fields containing heavy viscous oils occur principally in California and Texas. Portions of "giant" oil fields such as the Sunset - Midway, Kern River and McKittrick in California are classified as shallow heavy oil fields and are characterized by extensive outcrops of tar sand, breas and tar seeps. Below these outcrops are tremendous volumes of oil-bearing sands - well within reach by present open pit mining methods.

With the above background we can now consider the application of mining to the recovery of much higher percentages of the oil contained in shallow heavy oil fields and even from fields situated at depths up to 1000 - 2000 feet below surface.

Recovery by Mining

Basically, mining can be divided into surface mining and underground mining. Often an ore deposit may be mined from the surface initially and later from underground.

Surface mining may be subdivided into strip mining and open pit mining. In strip mining the overburden is removed above the "pay" seam and is cast laterally to be deposited in piles over areas from which the pay seam has been removed. After removing the overburden, the exposed pay seam is mined out and that area becomes available for deposition of the overburden removed from the adjacent advancing "strip". Ordinarily, huge draglines and power shovels are employed for overburden removal. Smaller power shovels and haulage trucks remove the pay seam. After mining, the disturbed overburden can be smoothed, graded and resoiled for farming, grazing, and other uses. Photo 1 shows a typical coal strip mine.

In open pit mining, the waste rock overburden is removed by power shovels, scrapers and trucks and is transported to waste dumps sometimes a mile or two distant from the ore deposit. As ore is uncovered it is mined with similar equipment and is transported to the reception bins ahead of the treatment plant or rail loading facility.

PHOTO 1

Strip Mining of Coal in Queensland, Australia
(Courtesy of Utah International)

Steady progress and intensive development of high capacity machines have made available to surface mining some astounding equipment: draglines equipped with 220 cubic yard buckets and booms over 360 feet in length; stripping shovels with dipper capacities over 140 cubic yards; bucket-wheel excavators which handle over 30,000 tons per hour; haulage trucks which can carry over 350 tons per load; tractors, front end loaders, rock drills, scrapers and graders, all of which are required in large surface mines. Many operations often move more than 300,000 tons of material each day; the Twin Buttes copper mine in Arizona has moved 550,000 tons in a single day and has reached a depth of 1135 feet below ground level. A view of the Twin Buttes mine is shown in Photo 2.

Underground mining is generally much more expensive than surface mining and the tonnages produced are smaller. There are greater hazards from rock falls, explosive gases, fires and flooding. However, it is possible to mine ore deposits which extend to over 8000 feet below the surface. At this writing, it is unlikely that oil-bearing formations can be mined economically underground at depths below about 2000 feet. However, some unique combinations of underground mining supplemented by thermal stimulation with steam are currently being successfully employed to produce heavy oil in Russia. This will be discussed in more detail later.

Block caving is a low cost, large volume, underground mining method and, given certain oil deposits which have a substantial vertical extent, might be applicable to oil sand mining. In block caving, the rock mass to be mined is undercut by numerous draw holes or openings and the material is induced to "cave" into the draw holes for subsequent withdrawal by gravity and hoisting to the surface.

Recent years have seen the development of versatile, efficient "trackless" or rubber tired underground mining equipment which can be driven from the surface to the underground ore bodies via sloping roadways in tunnels or declines. Such equipment and associated mining techniques are particularly applicable to the mining of bedded deposits such as coals, salines and thin oil sands via the room-and-pillar methods. Good ventilation is a requisite with such methods.

Early Oil Mining Operations

As was noted above, our earliest production of oil, tar and pitch was from hand surface mining of the oil seeps of Asia Minor and Europe. However, few people realize that underground mining of oil once flourished at a place named Pechelbronn in the Rhine Valley about 30 miles north of Strasburg, and at Wietze, near Hannover, Germany. Exploratory galleries were driven into the outcrop of bituminous sands at Pechelbronn in 1735 and the first mining concession was granted by the French King in 1745. Operations were small and there was no systematic ventilation. In 1870 wells were used to extract the deeper oil and between 1879 and 1899 over 200 wells were drilled to depths averaging 568 feet. After 1888 all underground work was abandoned and was not resumed for 25 years.

PHOTO 2

Twin Buttes Copper Mine, Arizona

In 1917, due to demands for oil during World War 1, Germany reopened oil mining and sank a 13-foot diameter circular shaft to a depth of 495 feet, and in 1918 production from the mine was 127,000 barrels of oil.

The source-sand beds for the mining operation ranged up to 30 feet in thickness and lay between beds of limy marl. The marls of the roof and floor were impervious to oil so extensive mine workings were developed chiefly in the marls above the oil sands. The oil sands contained about 12% of crude oil by weight, or 33 U.S. gallons per metric ton. Recovery was principally by gravity drainage into pits sunk into the oil sands from mine passageways driven in the marls above the sands. Therefore the term "oil-mining" referred to driving of accessways or entries for drainage of oil from the sands and not to actual excavation of the oil sand, except incident to driving of entries. Production from Pechelbronn apparently ceased about 1930.

Mr. George S. Rice, Chief Mining Engineer for the U.S. Bureau of Mines, made detailed studies of the French and German underground mines in 1929 and his excellent report entitled "Mining Petroleum by Underground Methods: A Study of Methods used in France and Germany and Possible Applications to Depleted Oil Fields Under American Conditions" was published in 1932 as Bulletin 351 of the USBM.

Figure 7 shows a plan view of the extensive passageways and laternals driven from vertical shafts in the oil sand bed of the Clemenceau mine at Pechelbronn in 1929.

Figure 8 is a cross-section illustrating the position of a gallery driven into the oil sand which lies between the marl beds, and Figure 9 shows the evolution of schemes to drain the oil into ditches and pits for subsequent recovery. Figure 10 shows sections and plans of certain workings utilized in 1930 to recover the oil. Note the production holes drilled laterally into the sand bed.

"Thermal Mining" Method

The "thermal mining" method is a development by the Soviet Union to produce high viscosity crude oils not recoverable by conventional means. It utilizes a proven concept of combining underground mining (for access to close proximity to the oil deposit) with in-situ processing to extract the oil.

The process was first used commercially in 1972 at the Yarega oil field near Ukhta, about 850 miles north east of Moscow. A recovery of 50 to 60% of the oil-in-place has been reported.

The Yarega field is about 650 feet below surface. Figure 11 shows a schematic cross section of the field. Conventional development with surface pumps yielded only 2% of the oil-in-place.

FIGURE 7

MAP OF CLEMENCEAU WORKINGS (1929)
IN LOWER SAND BEDS
(Area of Workings Is Approximately 3 Miles
Long by 1 Mile Wide)

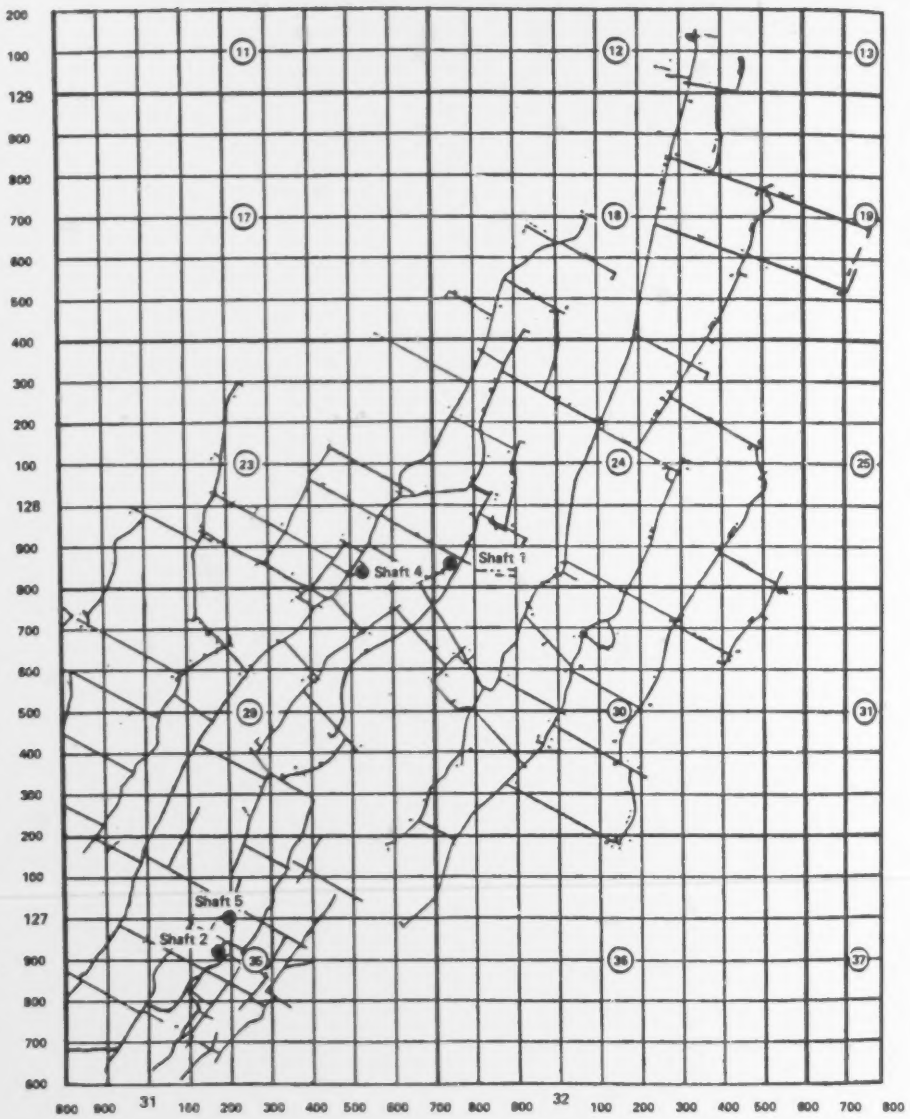

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FIGURE 8
TYPICAL SECTION OF GALLERY TO YEAR 1925

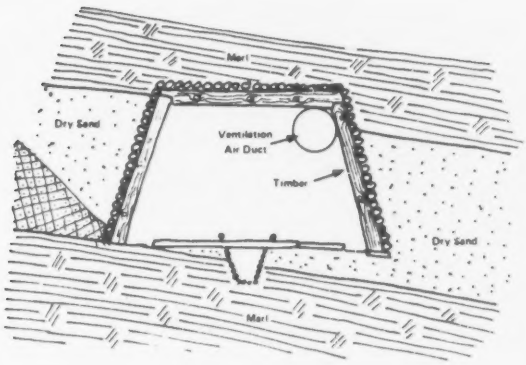


FIGURE 9
SUCCESSIVE POSITION OF GALLERY IN RELATION TO THE OIL SAND

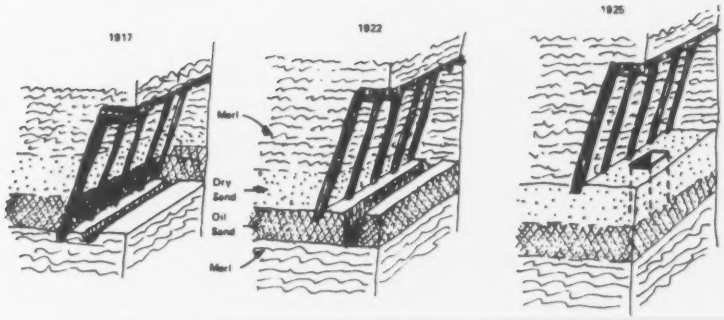
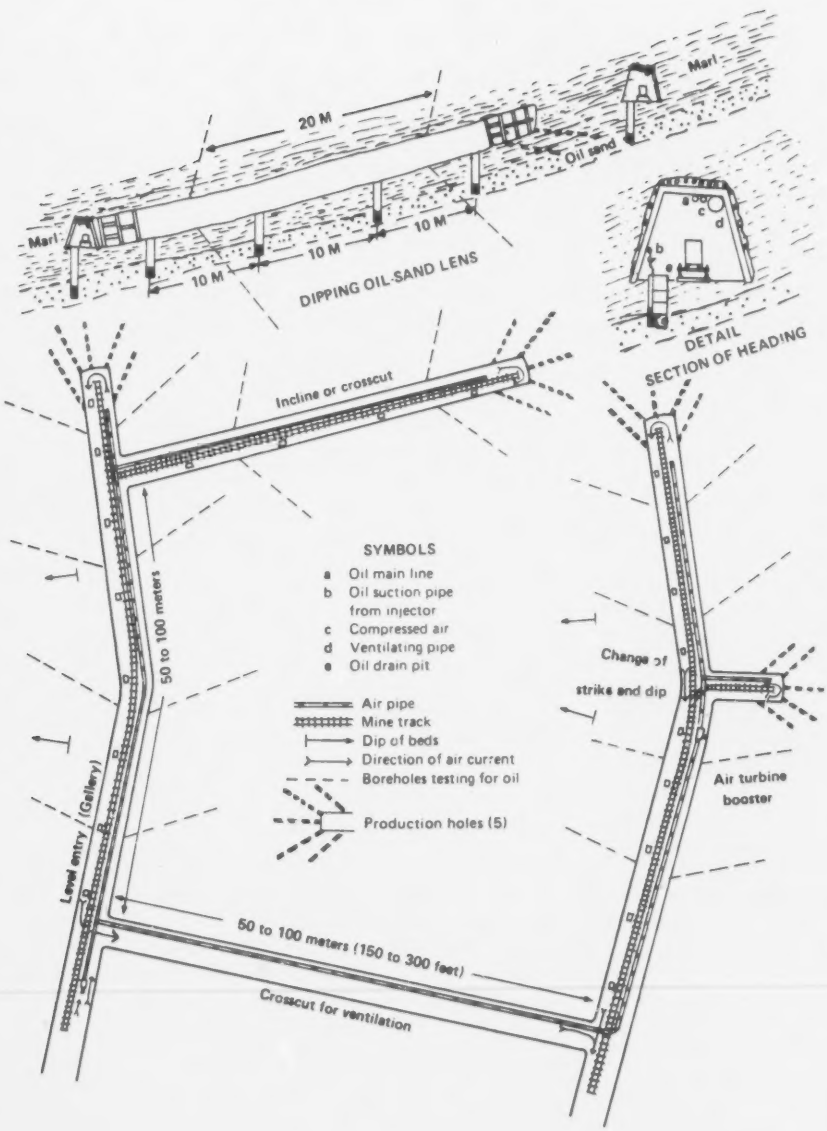


FIGURE 10
SYSTEM OF MINING (1930)
TO DRAIN OIL SAND



The basic idea of the thermal mining technique is to place men and equipment as close as possible to the oil productive zone. Access is by two vertical shafts sunk to a depth above the pay zone. One shaft provides transport for workers, equipment, recovered oil, and excavated material; the other is for ventilation. From the shafts, mine passages are constructed for drilling and production galleries. From these galleries production holes or wells are drilled into the pay zone with special drills. (See Figure 12).

Steam is injected into the reservoir sands through short holes drilled from specially constructed locations. After being recovered from the productive wells the crude oil is again heated at a central underground terminal and is pumped up a shaft to storage tanks on the surface. The rapid decrease in viscosity which accompanies a rise in temperature is shown in Figure 13.

Production is achieved from inclined access drifts located every 500 feet or so along mine passages which in turn terminate at production galleries in the reservoir. From these galleries several hundred feet of relatively short holes of small diameter (about 4 in.) are drilled horizontally or with an upward slope to serve as production "wells" with about a 50 foot spacing at the end of the holes.

If there is no appreciable ground water below the oil-bearing formation it is more advantageous to develop the mine workings under the oil sands so that gravity assists in the collection of oil through the production holes.

The Soviet experience indicates that the consumption of steam is about 2.5 tons per ton of recovered oil.

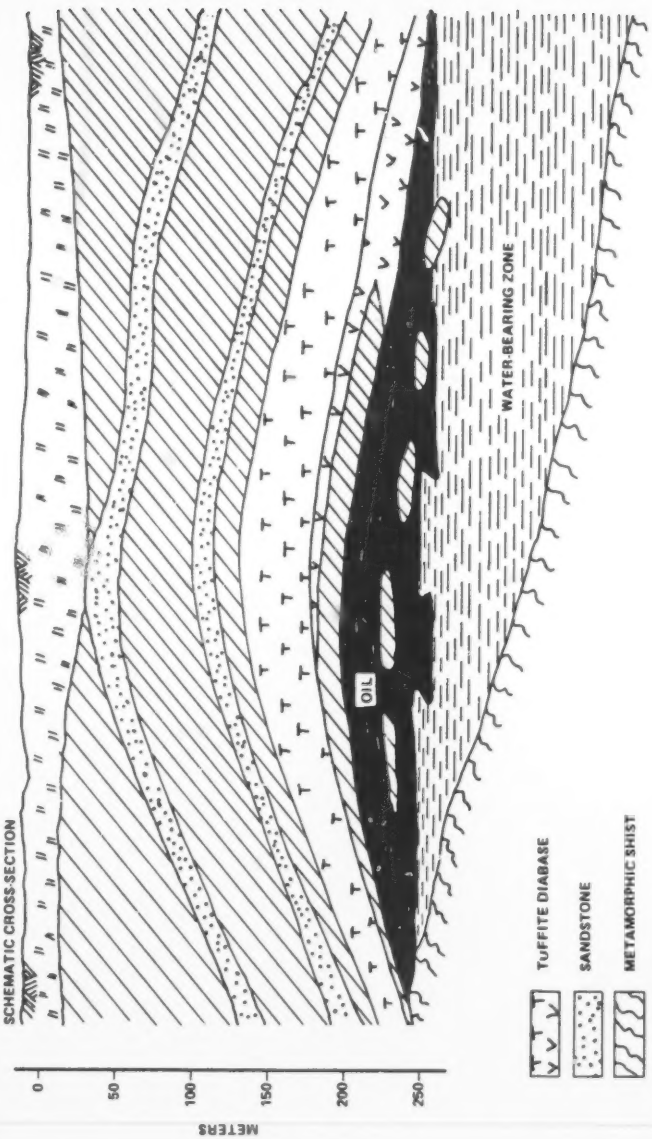
This is indeed an ingenious scheme and it is reported to be economically successful. The Soviets state that there are more than 300 Yarega-type heavy oil reservoirs in Russia. Although numerous productive zones range to a depth of 3900 feet, it is felt that the present technology limits application to deposits within about 2500 feet from the surface, probably due to ground pressures.

Work has already begun to develop an underground mine in a depleted area of an oil field northeast of Baku. Production will be carried on at a depth of 400 meters.

Open Pit Mining Projects

The largest open pit bitumen or tar sand mine now operating is that of Great Canadian Oil Sands near Fort McMurray in Alberta, Canada. Mining began at this 300 million dollar project in 1967 at a rated capacity of 45,000 barrels per day. To produce this volume of oil, GCOS had to move approximately 117,000 tons of material each day. In 1975 the output requirement was 55,000 barrels of synthetic crude per day.

FIGURE 11
THE YAREGA DEPOSITS



SOURCE: The Resource Sciences Corporation

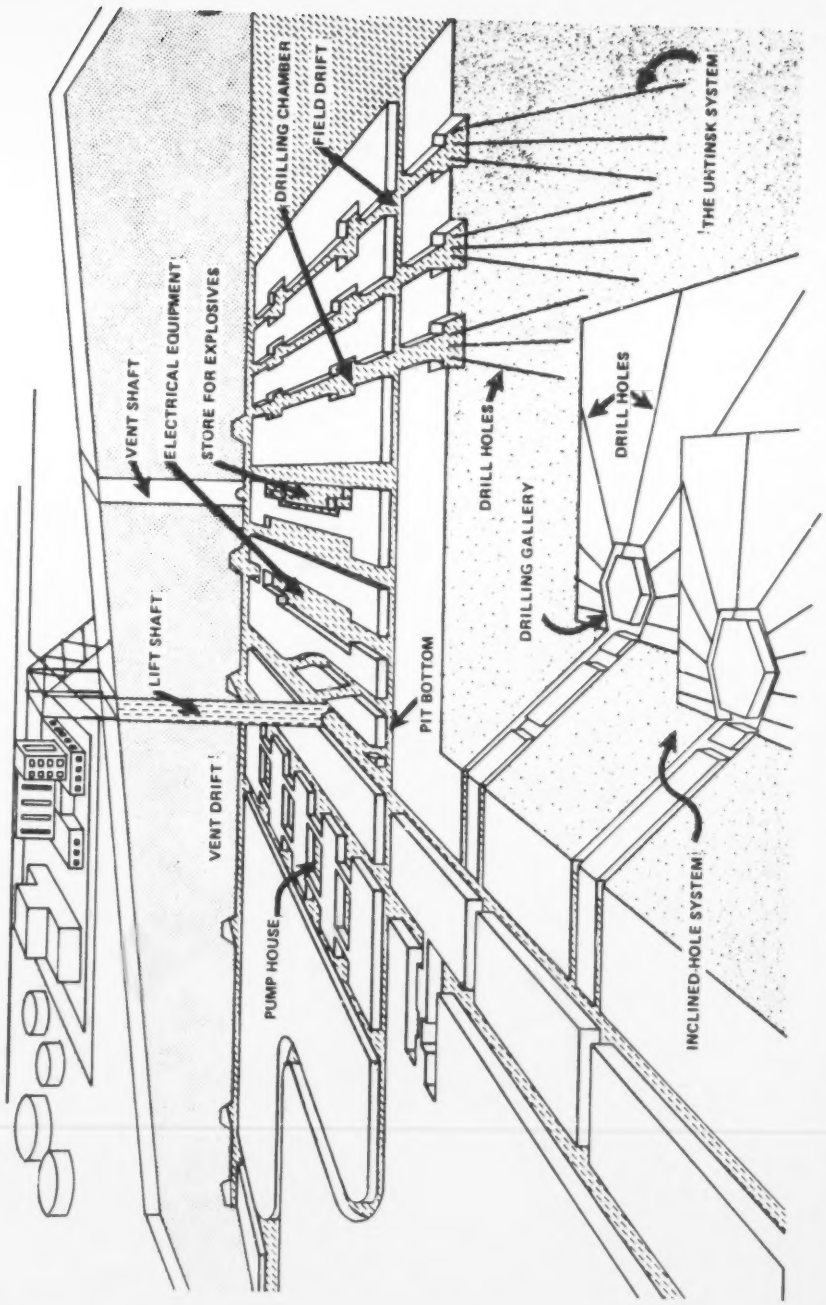
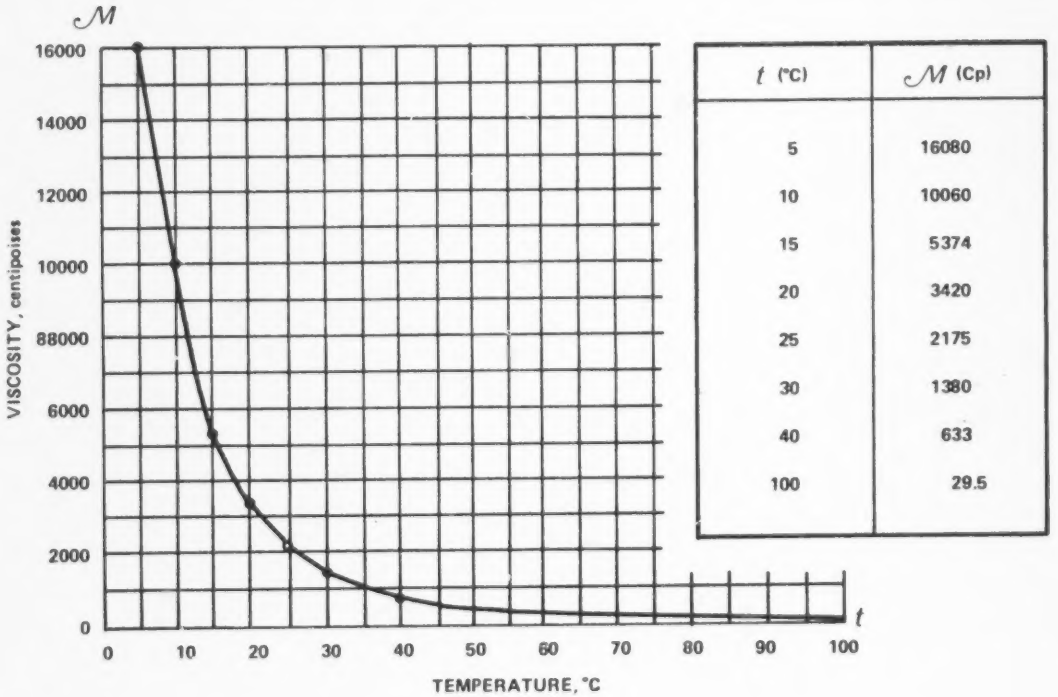


FIGURE 12
SCHEME OF THE YAREGA OIL PRODUCING MINE

FIGURE 13

VARIATION OF OIL VISCOSITY IN THE YAREGA OIL FIELD VERSUS TEMPERATURE



t (°C)	$\mathcal{M}$ (Cp)
5	16080
10	10060
15	5374
20	3420
25	2175
30	1380
40	633
100	29.5

Source: The Resource Sciences Corporation

At the GCOS mining site, the tar sands lie near-horizontally above a limestone bedrock. Overburden, consisting of muskeg, soils and clay, averages 53 feet but varies from zero to 150 feet in thickness. The tar sand varies from zero to 239 feet in thickness and averages 130 feet. The average "strip ratio" is 0.5 tons of overburden to 1 ton of tar sand. The bitumen content of the tar sand averages 12% but varies from 8 to 18% by weight.

The climate at the site greatly contributes to the difficulty and cost of the operation. Temperatures range to as low as 50 degrees F below zero. Location some 270 miles northeast of Edmonton called for costly construction of access roads, townsite and pipe line for the product, all in addition to the mine, process plant, refinery, power plants, workshops and utilities.

In the GCOS bitumen recovery process the mined tar sand is agitated with hot water and caustic soda at 180 degrees F in a rotating drum, followed by screening in which much of the rock and clay balls are removed. The undersize consisting mostly of already released sand and the bitumen is passed to flotation cells where the sand sinks to the bottom and is removed. The crude bitumen floats to the surface and is withdrawn and sent to the upgrading plant for removal of final impurities using further flotation and centrifuges. A recovery of 91% of the bitumen is reported. A simplified flow scheme is shown in Figure 14.

Due to the swampy character of the mine site, clearing and removal of the overburden is very difficult. Currently, the muskeg is removed in the winter when frozen, and after removal, the overburden then is stripped off in the summer with tractors and scrapers when not frozen. The actual tar sand is mined with large bucket-wheel excavators which discharge the mined material onto conveyor belts for delivery to the process plant.

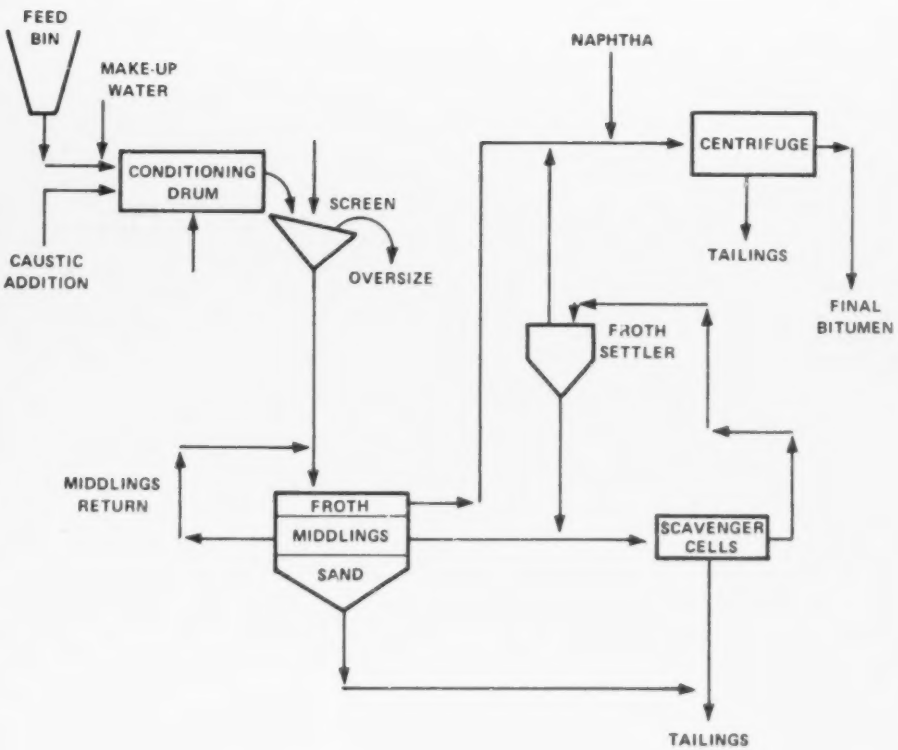
The overburden from the mine is used to construct huge dams for impoundment of the sand and slime tailings from the process plant.

After recovery of the bitumen it is heated in tall coking drums where the lighter hydrocarbons are driven off for further processing while the remaining coke is used mostly to fuel the power plant and to make steam for the process. Products include naphtha, kerosene and gas oil which are blended to form a high quality crude oil. Because the bitumen contains from 3 to 5.5% sulfur it must undergo desulfurization and a by-product of elemental sulfur is produced. Basic process steps are shown in Figure 15.

Other large scale operations are planned on the Athabasca tar sands, the largest being Syncrude Canada's 125,000 barrel per day project targeted for completion in 1978. Others are still in the planning stage.

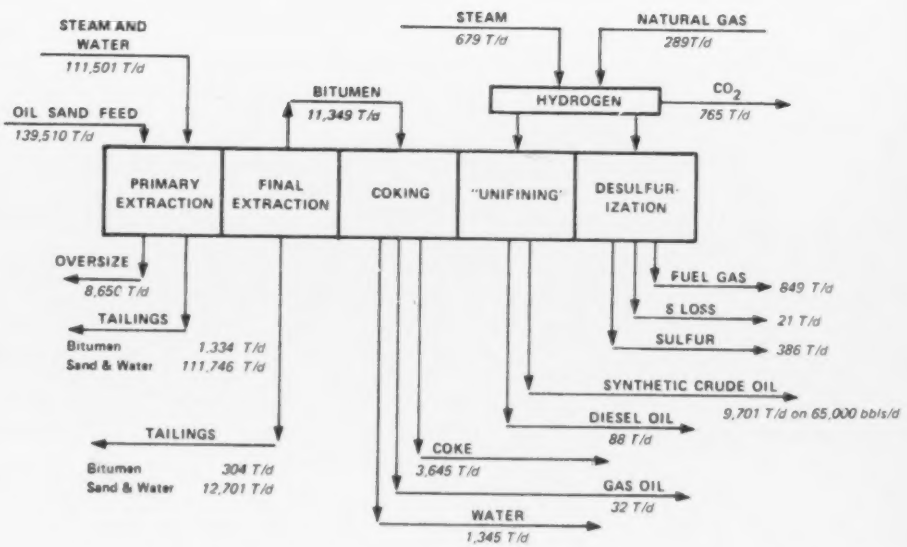
Although GCOS had an accumulated operating loss of over 93 million dollars during its first 7 producing years, they are overcoming problems and have had some profitable quarters. Much progress has been made and the special problems related to the physical

FIGURE 14
SIMPLIFIED EXTRACTION PLANT FLOWSHEET FOR GCOS PLANT



Source: Alberta Research

FIGURE 15
SCHEMATIC FLOWSHEET AND MATERIAL BALANCE FOR 65,000 BBL PER DAY OPERATION – GREAT CANADIAN OIL SANDS



Source: Alberta Energy Resources Conservation Board

characteristics of the deposit and climatic conditions are being solved, albeit slowly. It is the author's contention that if the financial burdens of: expensive access roads, townsite, power generation, transport of product to market, and high operating costs due to the severe climate were eliminated, there would be an attractive profit. In other words, the same mining and processing scheme in say, California, would be profitable.

Early in 1976 Russia announced plans to strip mine the extensive deposits in Azerbaijan where rich oil-bearing sands or bituminous rocks lie close to the surface. The Azerbaijan area is said to have more than 25 fields where reserves above 500 meters (1640 feet) total several hundred million tons of crude oil.

U.S. Early Tar Sand Projects

Because of the numerous outcrops of tar sands, breas and tar seeps in California, it is natural that attempts were made many years ago to develop production of oil from such deposits. The California Division of Mines Bulletin 176 describes several of such operations, the most famous of which is the Edna tar sand a few miles south and east of San Luis Obispo. Here bituminous sandstone deposits occur on both limbs of a syncline (See Figure 16). They range in quality from black, saturated tar sand to light-brown slightly bituminous sandstone. Oil probably originated in the underlying Pismo and Monterey formations and migrated upward losing its lighter constituents near surface and leaving asphalt. Estimated volumes are about 280 million tons of tar sand containing about 26 gallons per ton. There were reported to have been 27 quarries in the area, some opened as early as 1887. Some 80,000 tons of bituminous rock were shipped for paving in 1887-1890. In 1922, the California Oil Mining Co. drove several tunnels into the deposit and erected a plant designed to extract the oil by use of solvents. However, the operation was unsuccessful.

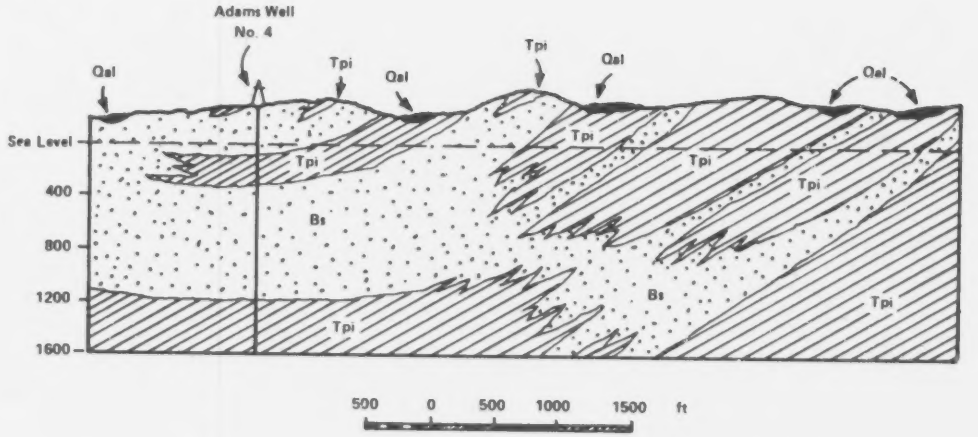
In 1943 the U.S. Bureau of Mines and U.S. Geological Survey initiated a study of the Edna deposits. A process for extraction of the oil by a "hot-water" method was developed as shown schematically in Figure 17.

Although these early attempts at recovery of the hydrocarbons were not successful economically, it must be remembered that crude oil prices in those days were generally $2.00 per barrel or lower. Secondly, large scale mining and processing equipment was not so fully developed as today.

Tar sands, usually being the outcrops of underlying oil fields, represent only a small percentage of the total volume of oil-bearing sands which extend below surface. The Edna oil field, for example, had a cumulative production to 1961 of 2.2 million barrels of 15 API oil. Total wells drilled were 122 and the average depth was 750 feet. The average thickness of the producing "Dollie" sand zone was 300 feet. We will now discuss some of the larger targets for oil mining - the shallow heavy oil fields.

FIGURE 16

CROSS-SECTION THROUGH
BITUMINOUS SANDSTONE DEPOSITS
NEAR EDNA
SAN LUIS OBISPO COUNTY



Qal = Alluvium and terrace gravel

Tpi = Pismo formation (Plio-Miocene)

Bs = Bituminous Sandstone

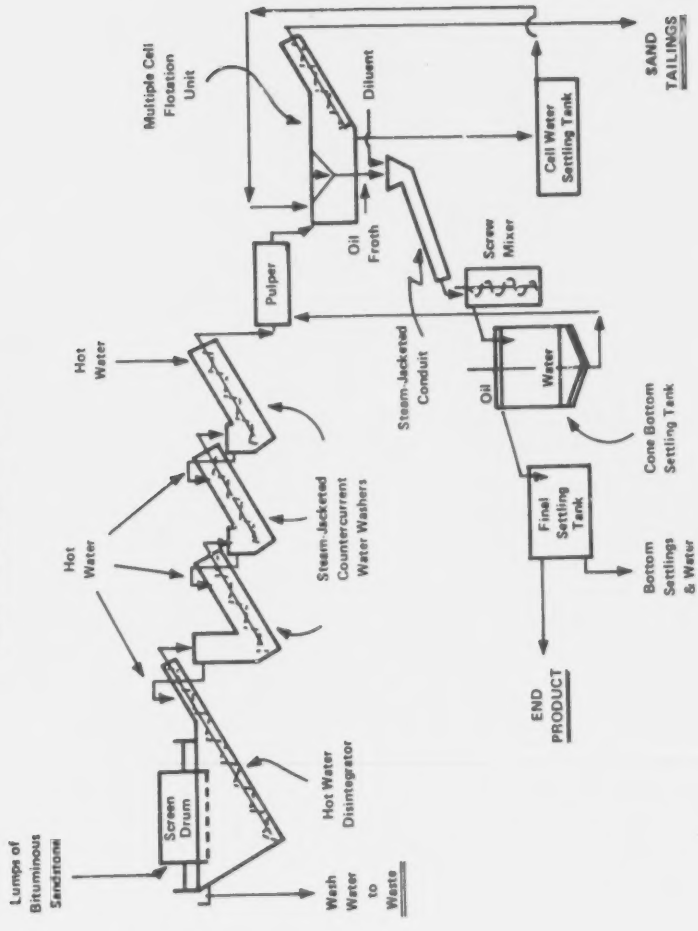


FIGURE 17
FLOWSHEET OF LABORATORY HOT WATER SEPARATION PLANT DESIGNED TO TREAT EDNA BITUMINOUS SANDSTONE

Source: U.S. Bureau of Mines R.I. 4246

Best Targets for Surface Oil Mining

California has been blessed with some giant oil fields which contain huge reserves of heavy oil at shallow depths, well within reach of present day open pit mining technology at acceptable stripping ratios. Some of the most important of such fields are the Kern River, Sunset-Midway, McKittrick and Belridge fields. From the standpoint of mining, these fields are huge "ore bodies" underlying thousands of acres of ground. Texas, Kansas and Missouri also contain a number of fields which could be mined. An abbreviated list together with some essential data on average depth and pay zone thickness are shown in Table VII.

Some idea of the size and structure of the Belridge and McKittrick fields can be obtained from the idealized sections in Figures 18 and 19. Brief summaries of data affecting open pit mining of certain California fields are shown below:

(1) Belridge South oil field. This certainly is a prospective open-pit operation. It is located in Kern County, 12 miles northwest of McKittrick, alongside State Highway 33, on the western edge of the valley.

Cumulative production to 1976 was 205.8 million barrels of 12 -15 API oil. The shallowest producing zones are the Tulare sands, which have a thickness of 400 feet and an average depth of 400 feet. Total wells drilled are 2526, over an area of 8000 acres (an anticline 8 miles long and 2 miles wide). Oil remaining in the ground probably exceeds 500 million barrels.

(2) McKittrick Oil Field. Two miles west of the town of McKittrick in Kern County is the McKittrick field. Like Belridge, it is a shallow anticline about 4 miles long and 1 mile wide. Cumulative production to 1976 was 212.3 million barrels of 12 -18 API oil. Average depth is reported as 500 feet, with 300 feet of producing formation, developed by 927 wells, but oil is found at the surface in places. It is estimated that 700 million barrels of oil remain.

Heavy oil was "mined" from open pits and shafts as early as 1861. Oil was obtained from numerous shallow wells drilled later; hence it is probable that considerable oil could be recovered from near-surface material. The sulphur content appears to be about 1%.

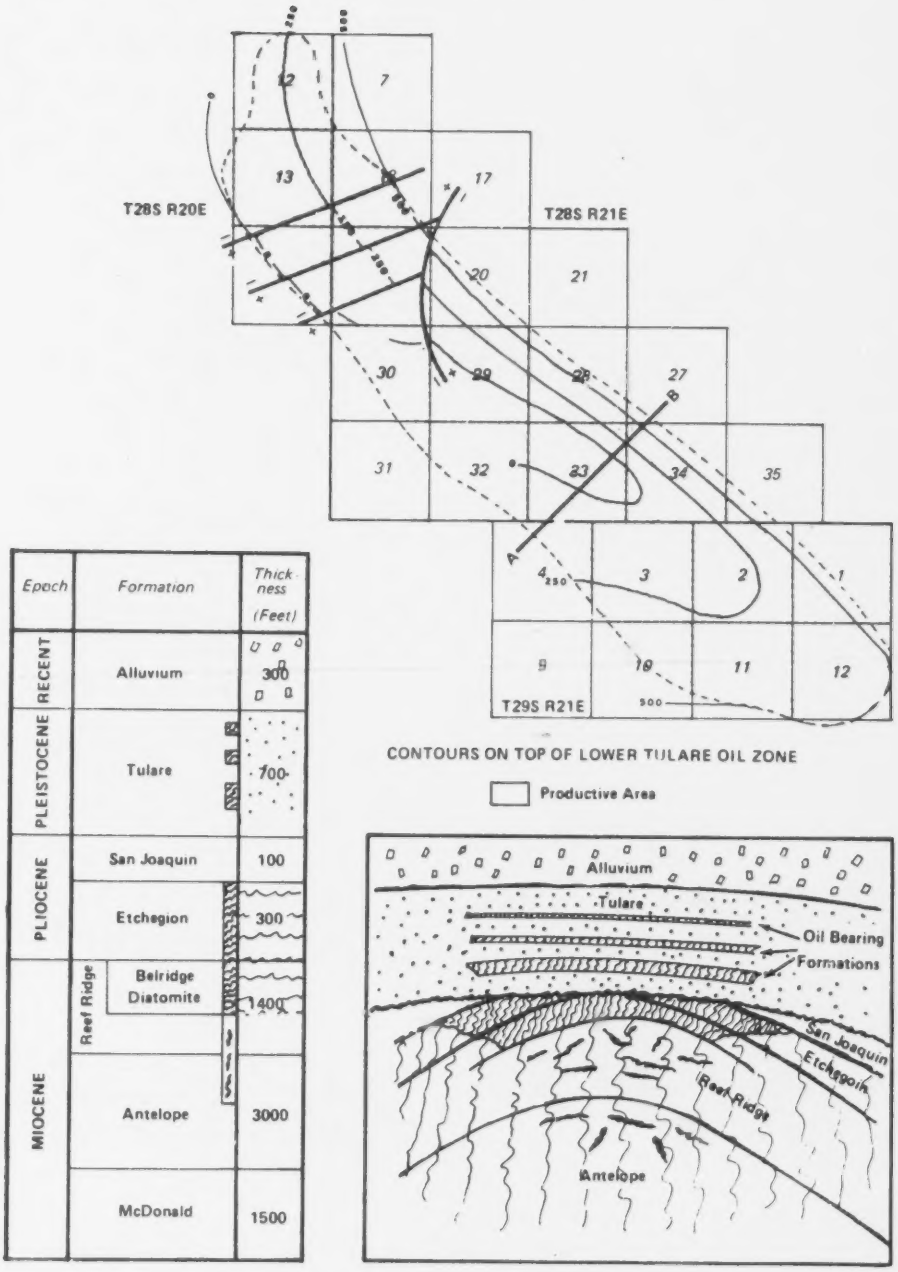
(3) Kern River Oil Field, located five miles north of Bakersfield along the Kern River. Cumulative production to 1976 was 659.0 million barrels of 13 API oil (much of which was sold at 12 to 18 cents per barrel.) Total wells drilled exceed 4780. The oil sand outcrops at the eastern edge and dips westward at about 5 degrees. Total thickness of the oil producing zone is 700 feet and "average depth" of the field is 900 feet. Proved acreage is about 9,000. If only 30% of the reserves have been recovered to date, the oil remaining in the ground is over 1,500 million barrels, a very worthy target for mining.

TABLE VII

SOME SHALLOW OIL FIELDS IN THE U.S.

Field	*Formation*	*Age*	*Avg. depth (feet)*	*Thick-ness (feet)*	*Oil grav. API*	*Disc-overy date*
TEXAS						
Pamela 150	Rustler	Permian	105	93	24	1957
Fasken	–	Permian	475	110	31	1949
Regular	Strawn	Pennsy.	126	?	?	1913
Atkinson	San Angelo	Permian	390	51	22	1960
Slocum	Carrizo	Eocene	480	48	20	1955
New Sweden	Serpentine	–	483	40	34	1955
Walt Pulazy	Pulazy	Lower Cretaceous	283	37	18	1961
Chittim	San Miguel	Upper Cretaceous	48	51	16	1962
Albrecht	85' Sand	–	85	17	?	1960
CALIFORNIA						
Kreyenhagen	Temblor	Miocene	300	100	17	1929
Devils Den	Salt Creek	Miocene	200	260	19	1901
Lost Hills	Tulare	Pleistocene	200	100	12-20	1910
Welcome Valley	Tumey	Oligocene	266	100	–	1952
Belridge South	Tulare	Pleistocene	400	400	12-15	1911
Kern River	Kern River	Pleistocene	30 to 1,300	30 to 700	13	1899
NE Edison	Chanac	MioPleistocene	350	120	12	1935
TipTop	Santa Margarita	Miocene	430	350	24	1918
Conejo Dewitt	Volcanics	Miocene	50	250	15	1892
Canyon Townsley	Top Moledo	Miocene	90	120	24	1882
Canyon	Moledo	Miocene	90	120	21	1893

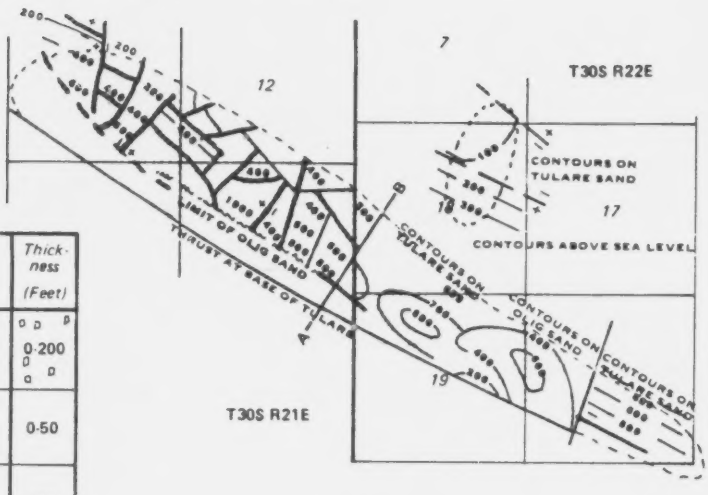
FIGURE 18
SOUTH BELRIDGE OIL FIELD



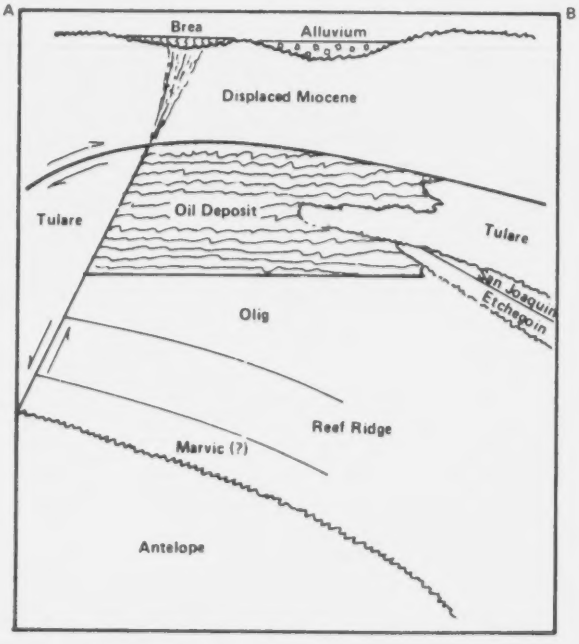
Source: California Division of Oil & Gas

FIGURE 19

McKITTRICK OIL FIELD



Epoch	Formation	Thickness (Feet)
RECENT	Alluvium	0-200
PLEISTOCENE	Tulare (Brea)	0-50
UPPER MIOCENE	Displaced Miocene	700
PLEISTOCENE	Tulare	300
PLIOCENE	San Joaquin	0-450
	Etchegoin	0-800
MIOCENE	Olig	1500
	Reef Ridge	
	Marvic (?)	
	Antelope	3000



Source: California Division of Oil & Gas

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Principal holders of the area are Shell, Getty, and Standard of California, which holds a major portion over the indicated thickest oil formation near the eastern outcrop. Field production in 1975 was 27,810,000 barrels. Average yield per producing well was only 16.6 barrels per day, even under steam stimulus. A view of a typical portion of the Kern River oil field is shown in Photo 3.

Oil Content of Sands

As is the case with mining of any solid mineral deposit, the quantity of the sought-after mineral in the crude rock or sand is a critical factor. In oil sands, it is the quantity of crude oil per ton of sand. It was pointed out earlier that the oil content generally depends on the porosity and absence of water in those pores.

Oil producers generally express the oil-in-place content of a reservoir in barrels-per-acre-foot: an oil sand with a high oil content may reach 2000 barrels per acre foot, or about 12% by weight and a low oil content sand would contain about half that quantity. In mining, the value of the crude ore usually is expressed as per cent of the sought-after product in a ton of material. A graph relating % oil by weight to gallons per ton and barrels per acre foot is shown in Figure 20.

To evaluate relative oil content, the following facts concerning tar sands, bituminous rocks, oil shales, and shallow oil sands are pertinent:

(1) The Athabasca tar sands contain an average of 27 gal per ton recoverable oil, or about 33-34 gal per ton in place. Highest contents are reported at 18% by weight, or 48 gal per ton.

(2) Colorado oil shales contain 28 gal per ton on the average: some strata of limited tonnage contain greater quantities.

(3) California bituminous sands can contain up to 80 gal per ton but probably average 30-35 gal per ton.

(4) Available data on US Midwest shallow oil sands indicate only 20 gal per ton.

(5) The actual oil content of shallow, heavy crude fields is presently indefinite but should be higher than that of a bituminous sand because the formation actually oozes some oil into wells.

Although the Kansas-Missouri-Oklahoma area contains very extensive heavy oil deposits, the porosity of the sands appears to range only from 18% to 25%, thus limiting the oil content.

Once the oil-bearing sand has been mined it must be tranported to an extraction plant where the oil values are separated from the waste materials. We have already seen that

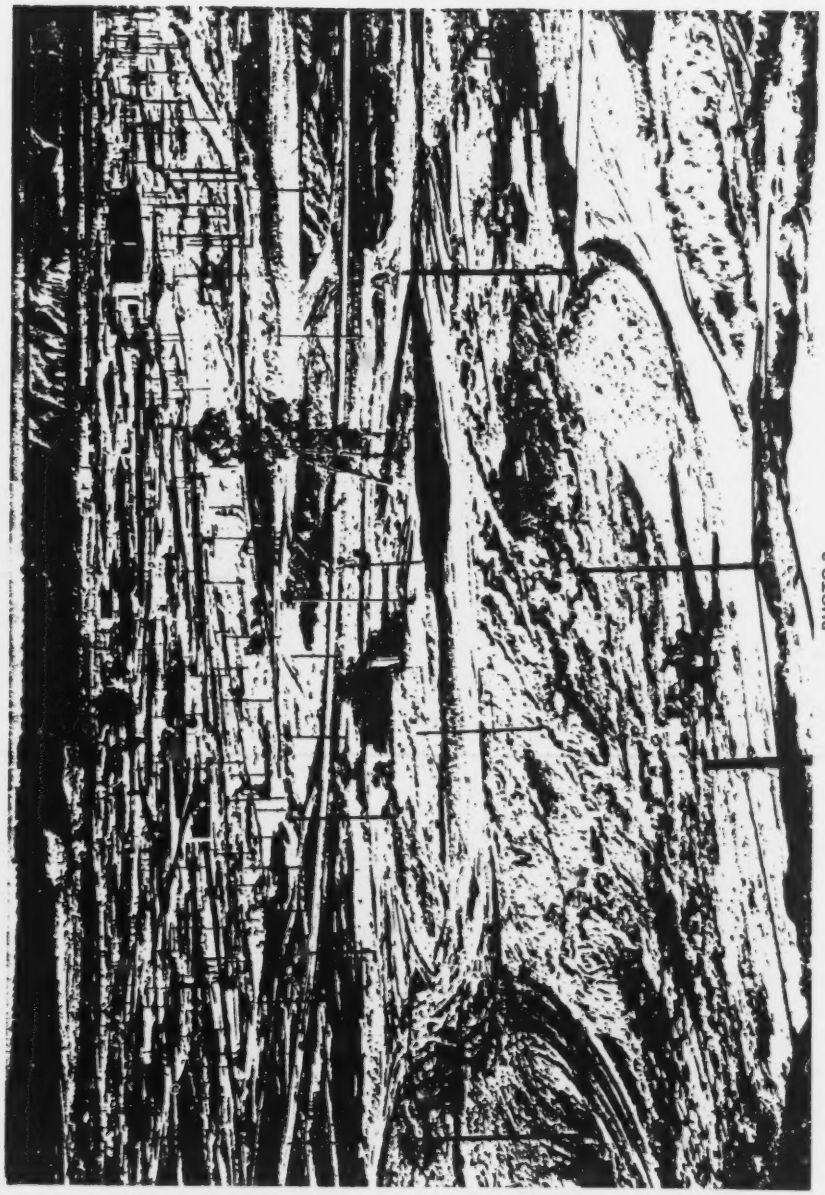
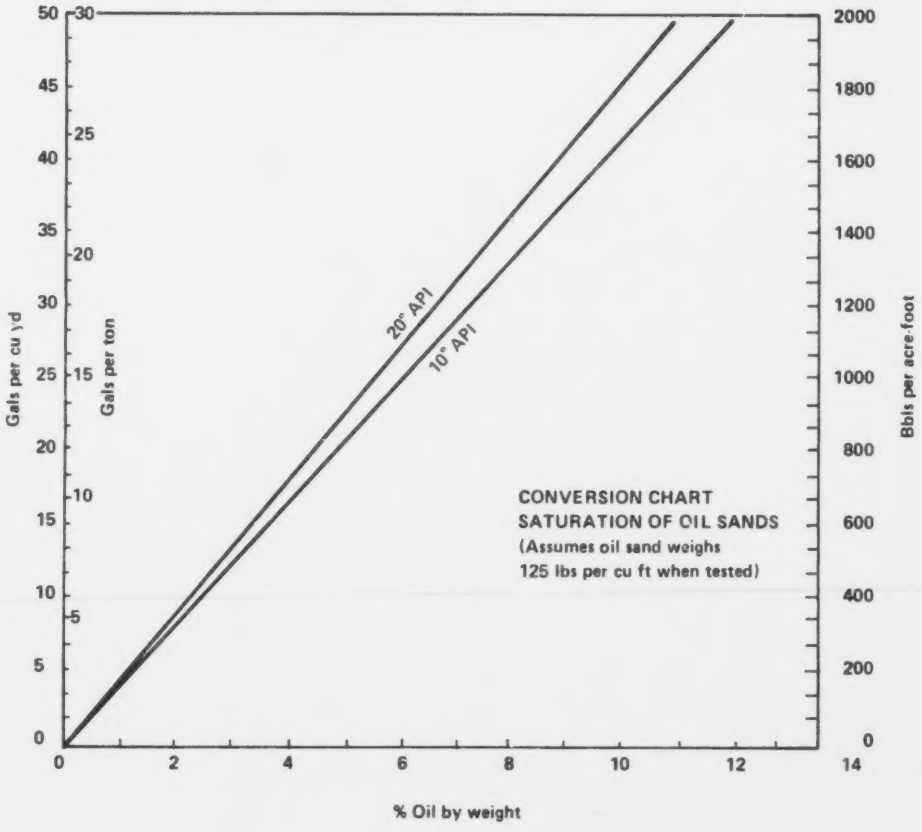


PHOTO 3

Portion of Kern River Oil Field
(Courtesy of Getty Oil Company)

FIGURE 20
OIL CONTENT FOR
10° AND 20° API HEAVY OIL



the "hot water" process is being used in Canada but there are other methods under development including solvent extraction and thermal distillation or pyrolysis. A large amount of money has been expended by various companies to develop pyrolysis methods for recovering the kerogen values from oil shales. Some of these techniques should be applicable to oil and tar sands and should recover from 90 to 95% of the contained oil.

Obviously, the cost to produce oil by mining will be higher than when sucking it from wells but we can no longer tolerate the low overall recoveries which are inherent with conventional well production.

For comparison purposes, let us assume that from a given shallow heavy oil field we can produce oil by thermal stimulation or steaming, and also by an open pit mining operation. Assume further that the steaming operation extracts 30% of the oil-in-place and that mining and hot water processing recovers 90% of the oil-in-place. We will also assume an oil content of 1 barrel or 42 gallons per ton of sand.

Table VIII shows the results. Mining provides 240% more oil for marketing than does steaming. Moreover, the effect on royalties to fee or mineral rights owners must also be considered; a lower royalty, reflecting the increase in costs to produce oil by mining, still brings a higher overall revenue to the fee owner.

A Near Ideal Open Pit Oil Mine

After careful study of available data it is possible to select several areas where a near-ideal open pit oil mine could be developed. One such site is on the western outcropping edge of the Sunset-Midway oil field in Sections 16, 17, 20 and 21 of Township 31 South Range 22 East. Here the oil-bearing Potter sand reaches thickness up to 900 feet under an overburden cover ranging from zero to 600 feet. An initial open pit over 5000 feet long and 2500 feet wide with 45 pit slopes and maximum depth of 900 feet below surface would make available to the extraction plant feed in excess of 170 million tons of sand containing an estimated 0.75 bbl per ton, at a strip ratio of 1.16 tons of overburden per 1.0 ton of oil sand. Moreover, this pit bottom would still be in oil sand. Down dip towards the east there are numerous wells producing from depths up to 2000 feet using thermal stimulation. Figure 21 shows a cross section through the proposed open pit and Figure 22 shows a plan view of the area.

Ample open area occurs to the West whereon stripping dumps and slurry tailings ponds could be developed. The location would not require housing for the workers; electrical power and a supply of process water is nearby; paved roads connect to valley cities and transport of the crude oil to refineries is already provided.

In view or the above favorable factors it is believed that there could be a viable pilot oil mining project at this particular site, with a capacity of 30,000 tons per day or 20,000 barrels of recovered crude oil. Continuity of the oil-bearing formation to the south and

TABLE VIII

COMPARISON – STEAMING VS SURFACE MINING

Assume: 1,000 Bbls. of crude oil in 1,000 tons of sand

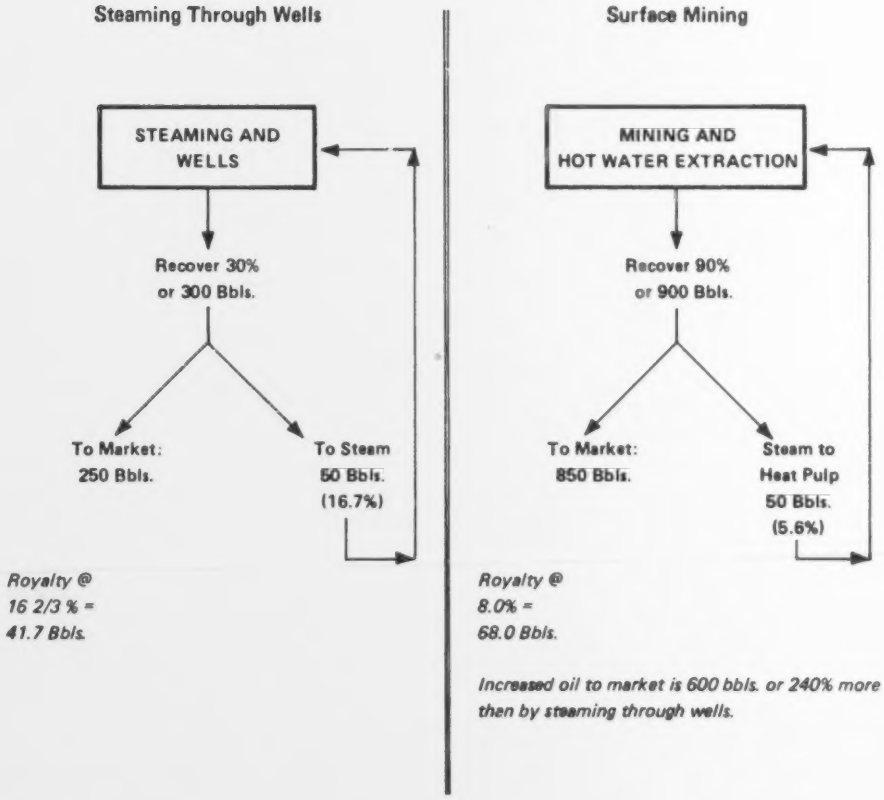

Steaming Through Wells
STEAMING AND WELLS
Recover 30% or 300 Bbls.
To Market: 250 Bbls.
To Steam 50 Bbls. (16.7%)
Royalty @ 16 2/3 % = 41.7 Bbls.
Surface Mining
MINING AND HOT WATER EXTRACTION
Recover 90% or 900 Bbls.
To Market: 850 Bbls.
Steam to Heat Pulp 50 Bbls. (5.6%)
Royalty @ 8.0% = 68.0 Bbls.
Increased oil to market is 600 bbls. or 240% more then by steaming through wells.

FIGURE 21

PROPOSED OPEN-PIT MINE

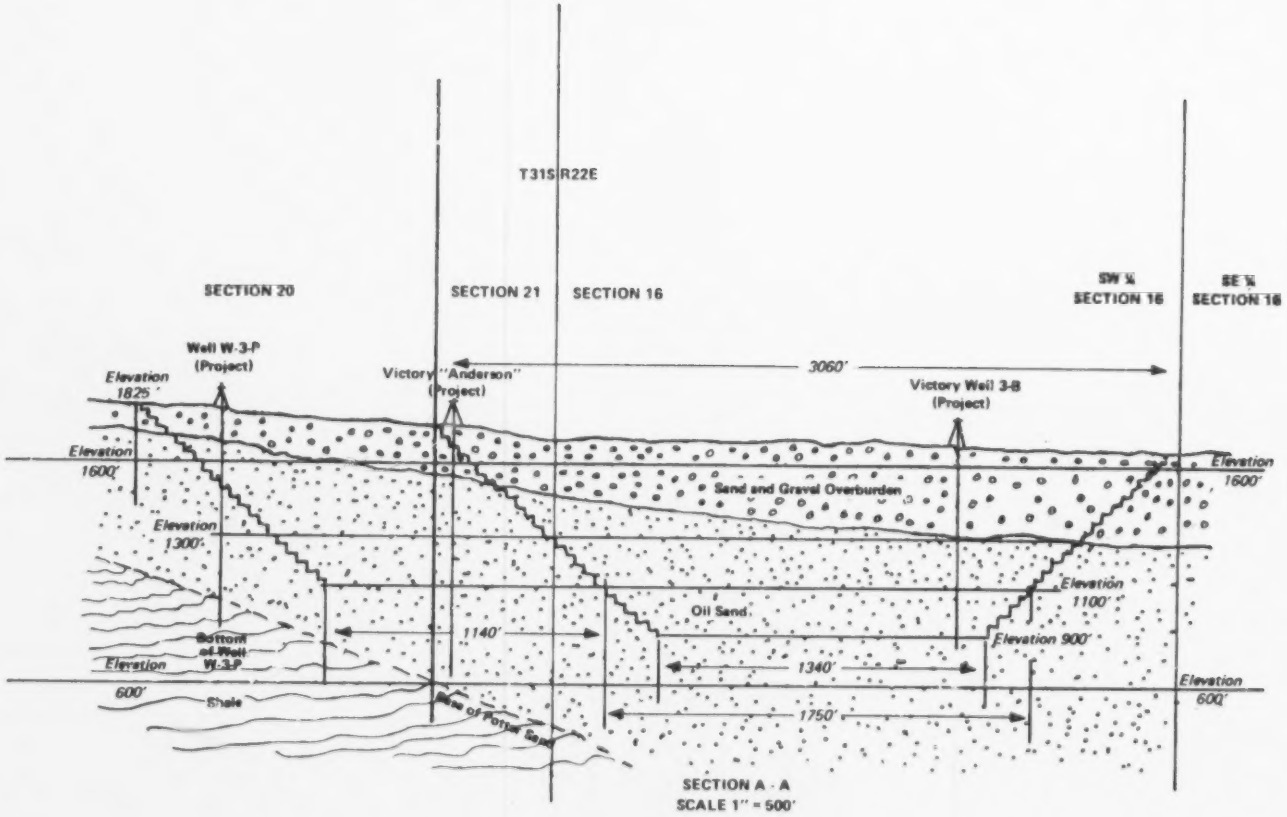
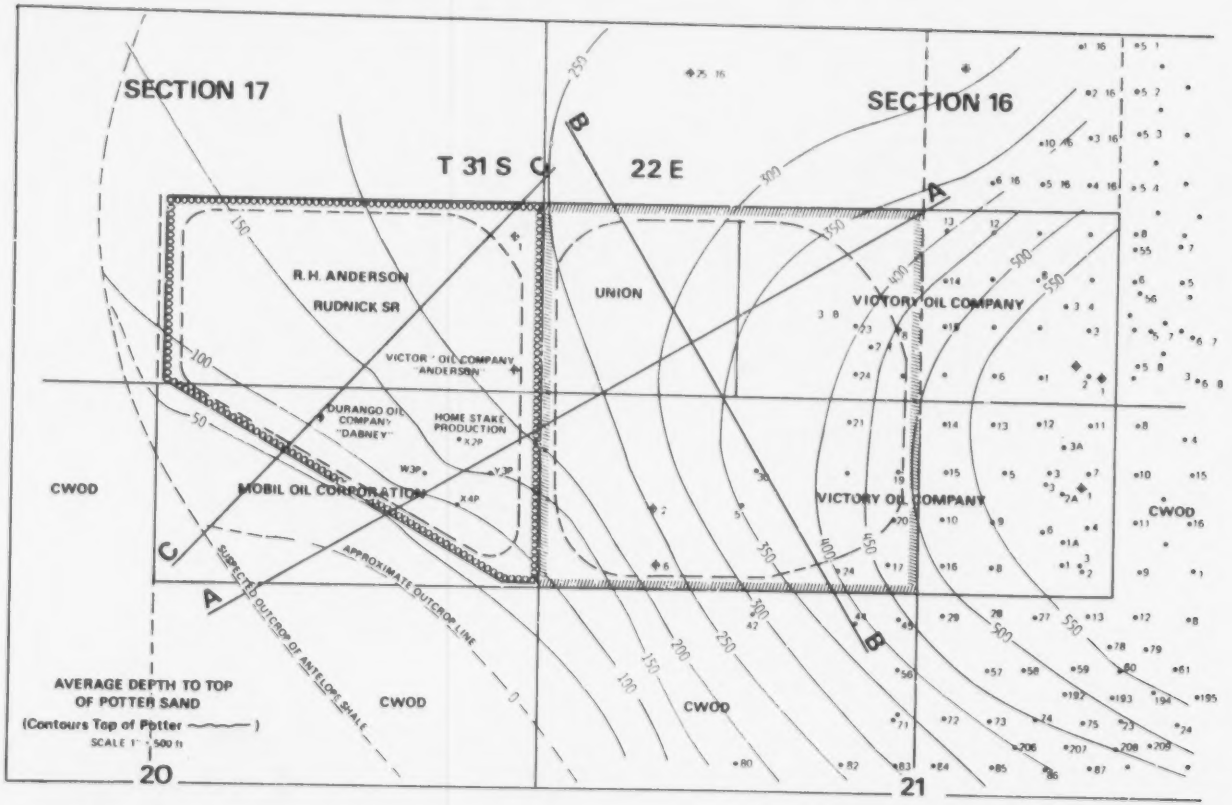


FIGURE 22
AVERAGE DEPTH TO TOP OF POTTER SAND
(GLOBE AREA – KERN COUNTY)



east assures that the pilot plant capacity could be increased to over 100,000 tons per day. Capital cost for such an operation should range from $6000 to $7000 per daily ton providing reasonable environmental regulations govern the operation.

In regard to tailings disposal, if a hot water process is employed, the sand tailings could be impounded initially, using disposal techniques and water reclamation systems well established in the copper, phosphate rock, and taconite iron industries. After open pit development has progressed to a certain point, sand tailings could then be deposited in the mined-out areas.

If a pyrolysis method is used for oil recovery, the residues could be handled in a similar manner. However, if placed in surface dumps they could be covered with topsoil and seeded with native grasses and shrubs for stabilization.

Broad Economics

When considering mining of oil sands, it is interesting to compare the operation with porphyry copper operations because the daily tonnages treated would be comparable.

Published financial data for 1976 shows that one plant of a major Southwestern U.S. copper producer treated an average of 80,000 tons per day of low grade ore which averaged only 0.31% Cu and 0.030% Molybdenum. This amounted to a gross value of $6.32 per ton with copper priced at 70 cents per pound and molybdenum at $3.30 per pound. Applying a recovery of 90% for both copper and molybdenum, the net value per ton was $5.69.

The steps required to extract the ore values included:

> Blasthole drilling, blasting, loading of the rock and ore into haulage trucks, transport of the waste rock to disposal dumps, haulage of the ore to the mill, then three stages of crushing, fine grinding, froth flotation, separation of the copper and molybdenum, dewatering of the concentrates and disposal of the tailings.

For porphyry copper mines, stripping ratios (waste rock to ore) range from as much as 6.0 to 1.0 to as low as 0.5 to 1.0. A good industry range would be from 1.7 to 2.3 waste to 1.0 ore.

Comparing oil mining with copper mining, there would not be blast hole drilling and blasting because the sedimentary overburdens and oil sands are softer and can be dug by rippers and scrapers. Stripping ratios can be lower. Virtually no crushing and grinding is required because the oil sand grains need not be reduced in size. (In copper ore processing, crushing and grinding are the major cost items.) And, finally, there should be no marketing problems for the product.

Therefore, if an oil mining operation were treating an oil sand containing from 0.50 to 1.0 bbl/ton of sand, it can be estimated that the operating costs would range from $3.53 to $5.48 per barrel of recovered heavy oil (Table IX). Assuming an average price of $10.00 per barrel, the margin of revenue over operating costs is substantial. (Recently, "stripper" well oil in the midwest was priced at $14.00 per barrel.) All indications point to a world minimum price of about $11.00 per barrel of crude oil for the foreseeable future.

Summary and Conclusions

The increasing consumption of crude oil, the depletion of our known reserves, the increasing difficulty and cost for discovering new deposits and finally, the grave political and financial risks associated with dependence on imported crude oil, all combine to demand that we should recover more of our reserves of oil-in-place. Intensive efforts are being made to raise oil recoveries from the dismal 25 to 30% range now being achieved. Mining, either by surface or underground methods, offers an attractive method to boost recoveries of heavy crude oils from certain types of deposits. By excavation of the oil sand and extraction in a special processing plant, recoveries of over 90% of the oil-in-place can be realized.

The costs for mining oil generally will exceed the present day cost for production from wells. However, calculations indicate that mining of shallow heavy oil fields will be more attractive and profitable than mining of oil shales.

Because of the benefits which will accrue to the United States through: reducing the dependency on foreign supplies, improvement in foreign exchange balances, greater utilization of our proven domestic petroleum reserves, and more employment opportunities for our workers, there should be tax reduction incentives for heavy oil producers who adopt oil mining techniques to increase output and recoveries.

Moreover, because the owners of mineral rights will receive more gross royalty dollars on higher recoveries of oil from a given deposit, there should be reductions in the current royalty rates to compensate for the higher cost of production by mining.

Our earth moving equipment and advanced technology for mineral processing combine to offer us the means to recover more oil. An assist from our government through tax incentives and reasonable environmental restraints will allow us to get on with the job.

TABLE IX

Estimated Operating Costs-Oil Mining
of a California Heavy Oil Sand
at 20,000 Tons Per day

	Unit Operation	Per Ton of Material	Per Ton of Plant Feed	Per Barrel of Oil Recovered* A	B	C
1.	Stripping Overburden (1.0 to 1.0 ratio)	0.30	0.30			
2.	Mining Oil Sand	0.35	0.35			
	Sub-total		$0.65			
3.	Feed Preparation		0.15			
4.	Oil Recovery Processing		0.75			
5.	Residue Disposal		0.10			
	Sub-total		1.65	1.83	2.44	3.88
6.	General & Administrative			0.75	0.75	0.75
7.	Royalty**			0.70	0.60	0.50
8.	Contingency			0.25	0.30	0.35
	TOTAL OPERATING COST PER BARREL			$3.53	$4.09	$5.48

*Based on oil recovery of 90% when treating sand with:

A. 1.0 bbl/ton oil content
B. 0.75 bbl/ton oil content

and 85% recovery when treating sand with 0.50 bbl/ton oil content (C).

**Assumed royalty on $10.00 per bbl. value of recovered oil:

7% of STB on 1.0 bbl/ton of feed
6% of STB on 0.75 bbl/ton of feed
5% of STB on 0.50 bbl/ton of feed

Statement for Energy and Natural Resources Committee

Energy and Mineral Resources Subcommittee

Prepared by E. M. Piper, Stone & Webster Engineering Corporation

March 2, 1984

Mr. Chairman and Subcommittee members; my name is Edwin M. Piper, Manager Process Industries Development at Stone & Webster Engineering Corporation's Denver Operations Center. I appreciate the opportunity to present the following remarks regarding the status of the technology of oil mining.

OIL MINING

Oil Mining is a quaternary oil recovery method to extract a higher percentage of oil from "depleted" fields or reservoirs which may have only yielded a maximum production of 35 to 40 percent of the original oil in place. In some specific reservoirs it is believed that only 20 percent of the original oil has been produced. In either case, some of these reservoirs are amenable to oil mining because secondary and tertiary methods of "enhanced oil recovery" are either exhausted or not feasible.

The quantity of the in-place oil resource in the U.S. has been reported to be as much as 300 billion barrels of oil. Oil mining could be the technology to extract an appreciable percentage of this resource but at this time is limited to the shallower reservoirs (less than 3,000 feet depth).

Oil mining has been used in varying degrees for thousands of years. In recent times there have been significant oil mining projects in France, Germany and the U.S.S.R. but there also have been several pilot

projects in the U.S. that have cumulatively produced an amount of oil equal to those projects.

Three mining methods are technically feasible which are surface extractive, underground extractive and mining for access (gravity drainage) although each has limitations. These limitations include specific reservoir characteristics such as the amount of remaining oil in place, depth, thickness, area, geologic complexity, temperature, oil viscosity, permeability, porosity and associated gas and water as the more important ones to be considered.

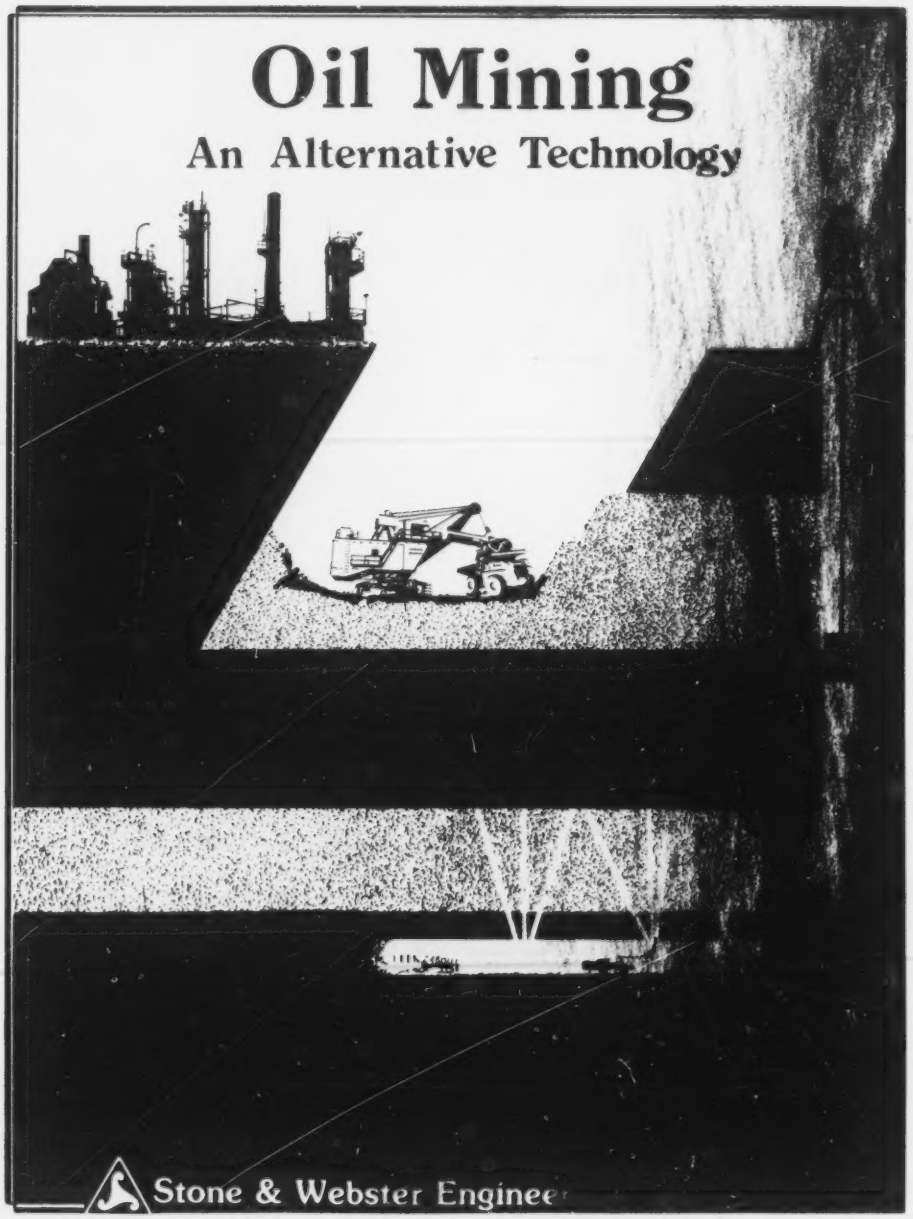
Mining for oil is valid for heavy or light oil production. From recent studies, the surface extractive method for heavy oil or tar sands may be economical and competitive at current world crude oil prices while heavy oil production from the mining for access method will require thermal assistance which does not make it competitive. The underground extractive method does not appear to be economically attractive at this time. In-house studies by Stone & Webster indicate that light oil produced by the mining for access (gravity drainage) method may be competitive with current crude oil prices.

Based on a study done by Stone & Webster for the Department of Energy, March 1983, titled "An Evaluation of Heavy Oil Mining," we found that the major costs involved in an oil mining project are for the access shafts and the network of drifts and rooms in the mining for access (gravity drainage) method. The major costs in the surface extractive method are for mining and processing equipment. Therefore, the mining costs are known to be higher than conventional drilling and production methods for recovering oil from a reservoir. The risks are known to be higher also. The combination represents a deterrent to the

private sector to fully developing the technology. Consequently, the technology of oil mining in the U.S. has not preceded as far as it otherwise could have.

Mr. Chairman, attached is a document prepared by Stone & Webster Engineering Corporation which describes in greater detail the oil mining technology, economics and also contains an illustration of a conceptual mining project for the mining for access (gravity drainage) method.

I submit this to you for the record. Thank you.


Oil Mining
An Alternative Technology
Stone & Webster Enginee

OIL MINING:

AN ALTERNATIVE TECHNOLOGY

STONE & WEBSTER ENGINEERING CORPORATION

APRIL 1983

OIL MINING: AN ALTERNATIVE TECHNOLOGY

Most of the oil produced in the United States is "light oil," or oil of 20° API gravity and higher. Typically, the oil is extracted from the reservoir using primary or enhanced oil recovery techniques, which have yielded a maximum production of 35 to 40 percent of the original oil in place. At this point the field is generally abandoned, leaving approximately two thirds of the resource in place, simply because it has not been economically or technically feasible to recover by conventional techniques.

Recent studies have shown that this in place resource could translate to 300 billion barrels of oil, or a 40-year supply of oil equal to the total amount of oil in Saudi Arabia. This is a significant resource that, if recovered, could put this country on the road to energy independence. The problem is how to extract it. These same studies have estimated that as much as 80 percent of this oil might be recovered by "mining" rather than by the usual method of drilling a well and pumping it dry, and that by using these methods it may be possible to produce oil for at least as much as or less than the current cost of OPEC oil.

Three mining methods appear to be technologically feasible. These are surface extractive mining, underground extractive mining and underground mining for access. Each has been attempted with limited success during the past 100 years. Each of these mining methods has limitations in its technical and economic feasibility for producing oil.

These limitations include remaining oil in place, reservoir depth, thickness, area, geologic complexity, temperature, oil viscosity and associated water and gas. The technical and economic limit for each variable depends on the mining method, but mining techniques will generally be limited to shallow reservoirs, less than 5,000 feet deep, with fairly thick, continuous pay zones.

Mining for oil is equally valid for heavy or light oil production. Recent studies indicate that the surface extractive and mining for access technologies may provide marginally favorable economics with moderate oil price increases. These studies indicate that heavy oil production from the mining for access method will require thermal assistance using steam injection, hot water injection or in situ combustion similar to existing projects that recover heavy oil from conventional surface wells. Light oil would not require thermal assistance and therefore would not be encumbered with the added costs associated with that aspect of production. Light oil production using mining for access may be economical at many available sites in the United States today.

An artist's impression of an oil mine is seen on the following page.

Historical Overview

Although oil mining represents a radical concept in oil extraction for today's market, mining for petroleum is really nothing new. The mining of rock outcrops for their oil content dates back to antiquity, and in fact, it was a feature of many local economies prior to the industrial revolution. The mining of oil, petroleum, asphalt, and other bitumens was practiced in the Sinai Peninsula and the Euphrates River valley prior to 5000 B.C. Mining was generally accomplished by shafts or wells sunk on the oil seep, followed by bailing with buckets or other containers. Later, as the technology progressed, shafts were sunk deeper and drifts were driven into oil sands to establish better drainage. These

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methods were practiced in Rumania, France, Germany, and other countries.

Rock asphalt, tar sands, and asphalt lakes in the New World were occasionally mined by surface techniques. Both Christopher Columbus and Sir Walter Raleigh reportedly used tar from a deposit on the island of Trinidad to caulk their ships for their sea voyages. Later during the nineteenth century, many east coast cities of the United States used this same material to make asphalt street paving.

While foreign countries have had varying degrees of success in recovering oil by underground methods, there has been relatively little research into oil mining in the United States. In 1932 a U.S. Bureau of Mines bulletin concluded that under certain conditions oil mining might be preferred over conventional recovery methods. This conclusion was based upon studies of oil mining methods used in Europe at oil sand mines in the Pechelbronn field (Alsace, France) and the Wietze field (Hannover, Germany).

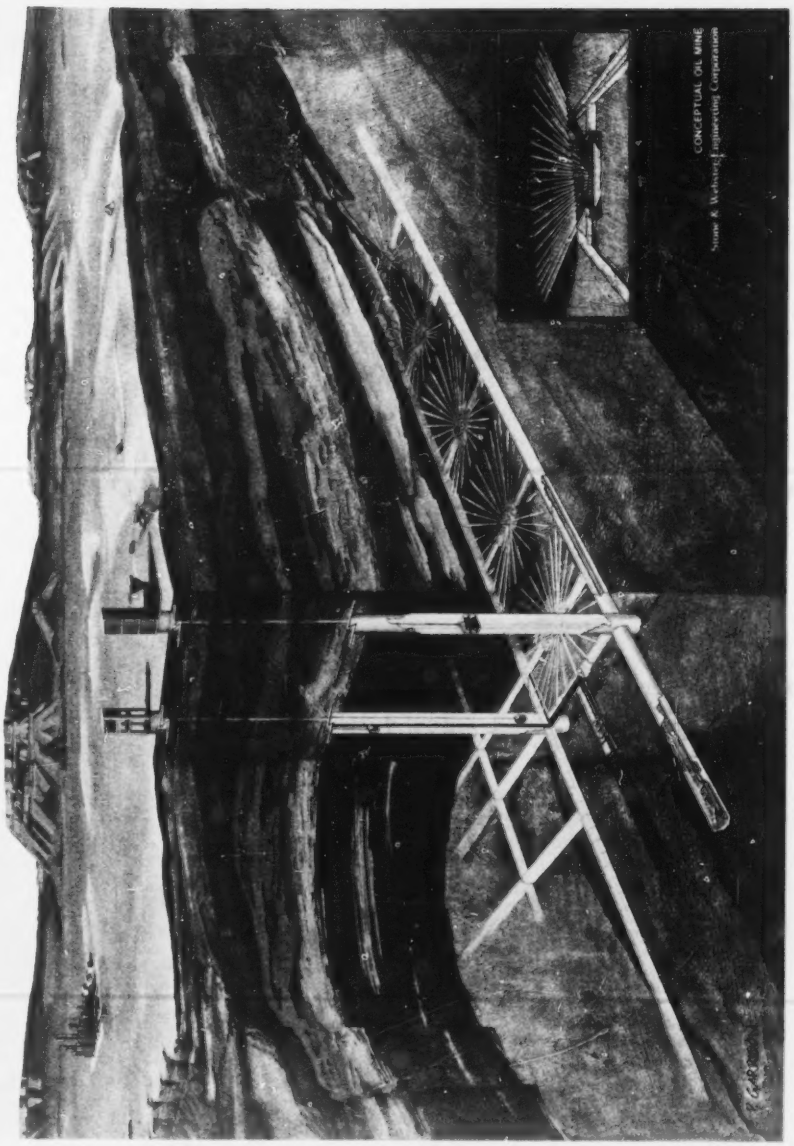
Is Oil Mining Feasible

Since then, there has been renewed interest in new technologies to recover oil that until now has been uneconomical to recover through conventional means. This corresponds with the nation's desire to be energy independent. Also, as oil fields are depleted and as exploration and drilling becomes more and more costly, it is becoming economically advantageous to recover further oil from known deposits.

This interest has resulted in several studies to examine the technical and economical feasibility of recovering oil by conventional mining methods. One was prepared by Golder Associates, of Golden, Colorado, titled "Oil Mining: A Technical and Economic Feasibility Study of Oil Production by Mining Methods." Energy Development Consultants, also of Golden, issued a report titled "Oil Mining." The most recent study report was prepared by Stone & Webster Engineering Corporation (SWEC)/Energy Development Consultants, Inc. (EDC) titled "Evaluation of Heavy Oil Mining."

These studies and the projects already underway show that there are many advantages to oil mining. For one thing, the United States has vast reserves--estimated at more than 300 billion barrels in known deposits alone--that cannot be tapped except by some form of mining, and tapping this resource is beginning to look more and more feasible from an economical, technical and philosophical standpoint.

Another advantage to oil mining is the amount of the resource recovered. Conventional, secondary and tertiary methods can recover no more than one-third of the resource in place, whereas recent studies have showed that mining could recover up to 80 percent of the resource. Mining for oil is also more advantageous environmentally when mining for access methods are used, because there is less disturbance at the mine site when compared to conventional mining operations. Since only a few smaller-diameter shafts are sunk and tunnels are used in a wide area underground, there is less surface disturbance than with conventional mining. This method is equally suitable for hilly country such as Kentucky and Ohio or for densely populated areas such as California. Using this method the tunnels are closer to the ore, and therefore more holes can be drilled at a lower cost, with no limit to the number of holes that can be drilled from underground. Also, since only disposal of the development rock is involved, there is no host ore to remove or process. This method is also less manpower-intensive. Since all the small holes underground have control valves, there is control over any gas and/or water encountered.


CONCEPTUAL OIL MINE
Stone & Webster Engineering Corporation

There is likely to be less subsidence with this method compared with extractive mining.

Despite these obvious advantages, oil companies have been reluctant to venture into oil mining. A primary reason is because oil mining as a technology is still largely an unknown, particularly in the United States. At the bottom line is economics: any oil mining venture would require a huge initial capital outlay with no assurances of equally huge profits. For instance, estimates have been as high as $600 million in capital outlay for only 20,000 barrels a day.

Another reason is that each project is very site specific, and hence it is difficult to assess the possible commercial success of any venture based on past experience. For example, two reservoirs may have the same amount of ore, but due to a number of factors such as location, host rock permeability, subsidence, temperature, etc., one field may obtain 100 percent extraction and the other only 30 percent. Another problem is that large quantities of water or gas may be encountered, and although control is easier with this method, there is still the problem of cleanup and disposal.

There are certainly some problems that would have to be surmounted in any venture into mining for oil; however, it is a technology with the potential to make vast increases in the recoverable oil reserves within the United States and the world. There are currently several demonstration-level projects in various stages of development and production which should do much toward proving oil mining as a viable technology and as an important factor in liquid petroleum production.

CURRENT AND PLANNED OIL MINING PROJECTS

United States

Most heavy oil produced in the United States today comes from tar sand deposits which are generally surface mined. Some recovery from existing production wells is accomplished by using tertiary methods. Presently there are only a few oil mining ventures in the United States in various stages of development. Some of the major international producers in heavy oil mining are shown on Figure 1.

The Getty Oil Company is working on two state-of-the-art processes to extract oil from a large deposit of diatomaceous earth in a field in California. This field has been producing oil by conventional means since 1896, peaking at 15,900 barrels per day. A program has been launched to test a solvent extraction process, developed by Dravo Corporation, and the Lurgi-Rhurgas retorting process, developed by Lurgi Mineroltechnik. These pilot facilities will run side-by-side to extract virtually 100 percent of the oil contained in the mined material.

The mining operation is a conventional open-pit mine, which is projected to produce about 34,000 tons per day of oil-yielding diatomaceous earth. Approximately 45 percent of the in-place oil is expected to be recovered, eventually yielding 380 million barrels of oil. Operation of the pilot plants will assist Getty Oil in determining which extraction method is best suited for commercial-scale development.

The Shell Oil Company plans to use mining operations to recover oil using an open-pit operation approximately 12 miles northwest of Getty's project. Shell is also analyzing the San Miguel sands of southwestern Texas for primary oil production. Two shallow

areas are being evaluated for surface mining and for thermal recovery.

American Mining and Exploration Company is planning an oil mining project in New Mexico, in 11,000 acres of sands. The company estimates that 250 million barrels of oil will be mined and processed with solvents, with a recovery factor of 95 percent.

Another oil mining venture is by Continental Oil Company (CONOCO) in the Powder River Basin, Wyoming. The project basically consists of a decline tunnel conventionally mined into a hillside to provide access to the oil sand from which an array of horizontal drainholes are drilled to varying lengths. In addition to the decline tunnel, CONOCO has completed a vertical shaft in the same formation, near the original site. At the bottom of the shaft a chamber has been mined, and several radial holes are currently being drilled.

The feasibility of producing light crude oil from a mine by gravity drainage is being studied for a field in Louisiana. Here, the Upper Cretaceous Annona chalk contains approximately 100,000 barrels per acre of 41-43 API gravity oil in place.

Cornell Heavy Oil Process, Inc. (HOPCO) has nearly completed an oil recovery demonstration project in a field in California to produce oil using steam injection and gravity drainage.

The HOPCO process involves excavating and creating a cavern constructed of reinforced concrete, which serves as a working chamber for drilling horizontal steam injection wells into the oil-bearing sands. A computer simulation model for this facility has defined a multiple cycle sequence of steam injection, steam soak, and heavy oil production. A five-cycle sequence for this site will require about 5 years of operational time to recover approximately 65 percent of the oil in place. Steam injection would average about three barrels of water equivalent for each barrel of crude oil produced.

Arco Oil & Gas Company of Plano, Texas, has been experimenting with an oil drilling rig which can deflect holes at right-angles. Field testing began earlier this year in an Oklahoma well for tapping oil deposits adjacent to a drill hole. Arco plans to use this new device to drill wheel-spoke patterns from an original hole for draining an area more completely of its oil. In another venture, Eagle Exploration Company plans to start drilling in the Black Hills uplift this year to lay the foundation (cores and geological data) for a steam project for heavy oil recovery in northeastern Wyoming.

Tetra Systems, Inc., of Golden, Colorado, is aquiring property in Ohio to implement a mining for access method for recovering oil. They reportedly have acquired 200,000 acres of depleted oil leases in the United States.

New Tech Oil Inc. is a small, private firm formed specifically for oil mining. They now have a small pilot oil mining project in Ohio.

Foreign Countries

Foreign companies are generally more advanced than the United States in the technology of oil mining. Other nations have had more success, and many are actively experimenting with mining technologies and their application for recovering both light and heavy oil. In France, pilot operations using both microemulsion and polymer flooding have shown satisfactory yields in the Chateaurenard Field in the Paris basin. A steamflood process is also underway in the Laoq Field in fractured limestone, again with favorable results.

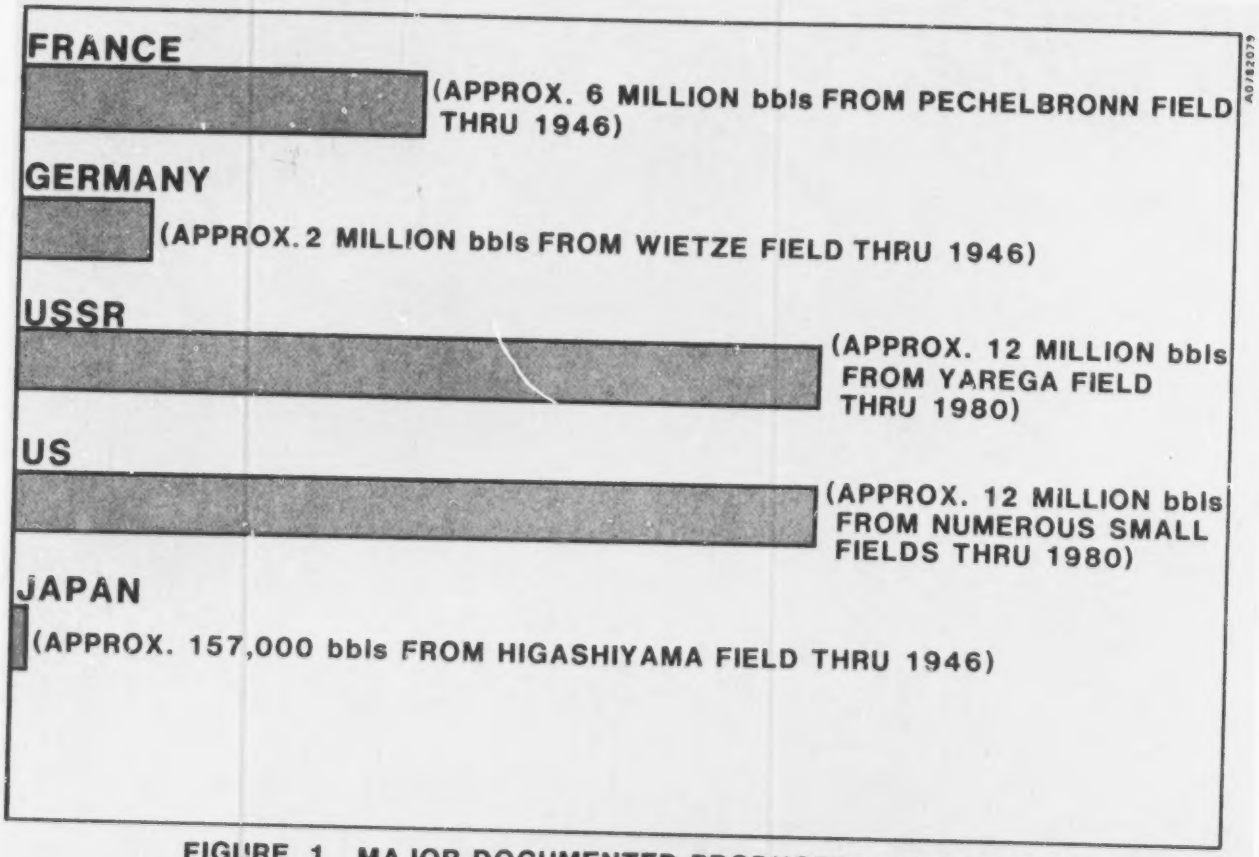

FRANCE
(APPROX. 6 MILLION bbls FROM PECHELBRONN FIELD THRU 1946)
GERMANY
(APPROX. 2 MILLION bbls FROM WIETZE FIELD THRU 1946)
USSR
(APPROX. 12 MILLION bbls FROM YAREGA FIELD THRU 1980)
US
(APPROX. 12 MILLION bbls FROM NUMEROUS SMALL FIELDS THRU 1980)
JAPAN
(APPROX. 157,000 bbls FROM HIGASHIYAMA FIELD THRU 1946)
A0182079

FIGURE 1 MAJOR DOCUMENTED PRODUCERS OF HEAVY OIL

The Japan National Oil Company has conducted some research in improved oil recovery processes. Most of the major activity in heavy oil recovery is being conducted with a group of companies in the oil sands of Alberta, Canada, applying steam with electrical preheating.

The production of oil from the tar sand deposits in Canada has become increasingly more economical in the last several years. Many private companies are spending large sums of money to develop systems to recover these oil reserves and to date, all have been surface mining operations. The largest venture is in the Athabaska tar sands of northeastern Alberta.

Another Canadian operation is sand mining by removing oil sands from underlying limestone and bringing the tailings from the processing plant. With an input of 140,000 tpd of oil sand and an overburden removal of 70,000 tpd, the plant output is about 55,000 barrels of oil per day with 90 percent recovery.

With 92 percent of the in-place heavy oil in Alberta lying at depths of between 150 to 2,500 feet, surface mining techniques would be prohibitively expensive; therefore, in situ techniques are being researched in order to eliminate bulk materials handling and reduce many of the environmental problems associated with surface disturbance. In one in situ project, Amoco Canada is using a combination fire flood/water flood process. Shell Canada, Ltd. has successfully experimented with forming horizontal fractures to establish subsurface flow of oil between injection and production wells. Steam injection has been used by Imperial Oil, Ltd., Shell Canada, Ltd, and Gulf Oil Canada to recover heavy oil from bituminous deposits.

In 1978 Petro-Canada began work on a horizontal drilling project at an outcrop site. Drilling was begun in the spring of 1979 and steam injection started in August of 1979.

In 1968 the Soviet Union developed a new underground mining method to recover heavy viscous oil at the Yarega Field near Ukhta, northeast of Moscow. This method combines closely-spaced wells from underground chambers and steam injection. Recovery improved to approximately 40 percent, mine production increased, and the cost of production per barrel of crude dropped by half.

The Yarega method is essentially an in situ process, with only a small amount of development rock to be handled. It can recover high viscosity oil not recoverable by conventional pumping. Viscosity of the heavy oil is lowered dramatically by the application of high-intensity, low-pressure steam. Both steam and production wells are drilled primarily into the pay zone, allowing for higher thermal efficiency, rather than in barren formations between the surface and the pay zone.

Because of the encouraging results at Yarega, the Soviet Union began preliminary work in 1976 on a new commercial-size underground heavy oil mine to test the economic feasibility of an underground mine for the recovery of heavy oil from the 100-year-old Balakhany field near Baku in Azerbaijan. Two vertical shafts will be sunk below the pay zone, with large horizontal tunnels similar to drifts in coal mines connecting the shafts. Small-diameter holes will be drilled upward at varying angles from these tunnels into the pay zone, allowing viscous crude oil to flow downward by gravity into storage tanks. While the opening of the first underground mine in the Baku areas was originally scheduled for 1978, delays in design, equipment, electric power lines and government funding have pushed the start-up date from late 1982 to 1983.

The Soviet Union is also planning to recover heavy viscous oil from off-shore fields in Azerbaijan by undersea mines. Two methods of reaching the deposits are feasible, depending on the distance of the oil field from shore and the water depth. When the prospective oil field lies near the shore or on an island where the water is more than 330-500 feet deep, a vertical shaft will be drilled on-shore to a level 200-260 feet below the sea bottom. Horizontal drifts will then be bored at that level, running from the vertical shaft for the full length of the underlying oil field. For oil fields lying far from shore in depths of less than 330-500 feet, a vertical shaft (caisson) will be located off shore and set in place on the bottom of the sea over the center of the oil field. Once the caisson is in place, a vertical shaft will be drilled to a depth of 200-260 feet below the sea bottom, with horizontal drifts radiating outward from the vertical shaft the extent of the underlying oil field.

To recover heavy oil from beneath the ocean one of the Yarega methods will be used, or an adaptation of one of the methods being developed for the Balakhany underground mine in Azerbaijan. Experience at Yarega has shown that the spacing of production and steam injection wells is the most important single factor in the coefficient of recovery. Closer spacing results in lower steam losses, faster heating, and greater and quicker extraction of heavy oil from the mining section.

Since 1973 the Soviets have been testing a new variant of the fire-flooding technique at two old Azerbaijan oil fields north of Baku. With a 25-kw electric heating unit installed in the wells at the pay zone level, compressed air is injected into the reservoir through specially drilled ignition wells and heated as it is forced into the reservoir. Recovery from this technique has been reported to be as high as 54 percent of heavy in-place oil.

The Soviets estimate that there are at least 25 heavy oil fields in the Baku area at a depth of 1600 feet or less where various mining methods can be applied successfully. The first commercially-operated heavy oil field, by the in situ combustion process, was in the Khorosany area of Azerbaijan. Started in 1973, it was converted to a "wet" combustion project in 1974. By 1977 it was producing 3 1/2 times the rate in 1972 by conventional water flooding.

In addition to steam and combustion processes, the Soviets are also working on two other methods of in situ heat generation: electrical downhole heating and thermochemical heating (hydrochloric acid and magnesium treatment). Polymer flooding has been successfully field tested in the Kuyibyushev region, Bashkiria, and the heavy oil deposits of the Tartar region. While extensive research on chemical flooding is being conducted by the All-Union Research Institute in Moscow, no field testing is being conducted.

There are known deposits of heavy oil in Brazil. The Brazilian national oil company, Petrobras, was working with American consultants on techniques such as polymer flooding and micellar slugs. More recently, a heavy oil reservoir was discovered offshore near Rio de Janeiro.

The largest known heavy oil field in Indonesia is in central Sumatra, with about 3 billion barrels of in-place viscous oil. Other known heavy oil fields are in southern and offshore Sumatra and in Borneo. The only known heavy oil recovery process currently in operation is a steam-soak project operated by Calter Pacific, of Indonesia, in central Sumatra. Despite major problems, the effort has shown promising results with ultimate recovery expected to significantly surpass the less than 10 percent primary recovery.

Heavy oil deposits in Peru occur primarily in the northeastern portion of the country, which is estimated to have approximately 1.5 billion barrels of in-place oil. Occidental Petroleum Corporation has initiated pilot projects for development of reservoirs which normally produce oil by a natural water-drive method.

Estimates of heavy oil deposits in Trinidad are as high as 40 billion barrels. Currently, Texaco and Tesoro-Trinidad are pursuing heavy oil recovery by a steam displacement process.

All known heavy oil deposits in Turkey lie in the eastern part of the country; however, recovery has been attempted in only one field, Bati Raman, discovered in 1961. By 1967 primary recovery had yielded only 1.5 percent of in-place oil. Since then, water flooding, continuous and cyclic steam injection, and air injection have been attempted on pilot projects. Engineering studies are currently underway to evaluate alternative recovery methods.

APPROACH TO AN OIL MINING VENTURE

So far U.S. oil companies have been reluctant to get into oil mining. As mentioned previously, it is a new technology with some obvious technical disadvantages, and any such venture would require huge capital outlays. Also, there is much confusion as to exactly how oil mining will be regulated and taxed. The government appears to be favorable to the development of this technology and is encouraging industry to move forward with demonstration projects. It appears that oil mining may be exempt from the windfall profits tax, and incentive programs with tax credits may be created to encourage further development. At this time, however, there appears to be some confusion whether to regulate this technology under mining or petroleum.

It is not entirely clear how an oil mining project would be leased or how potential conflicts with surface activity would be resolved. Mining claims and petroleum prospects may be leased separately, and conflicts may result when a reservoir is tapped from below using a mining for access scheme in a reservoir that is also tapped from above using surface wells. Surface mining, on the other hand, would eliminate surface wells altogether. These conflicts could lead to costly lawsuits, which would be detrimental to both parties involved. On the other hand, through a cooperative effort, both parties could benefit. For instance, in underground mining for access technology, the surface wells would be used to inject steam, water, or chemicals to force the oil downward into the mine's production wells.

Selecting a Site

A logical method for going from selection of a reserve to actual commercial development is to proceed in two phases as outlined on Figure 2. The first phase would be selection of a specific site to mine for oil, and the second phase would be to develop a small demonstration pilot project on part of the area to test the technical and economic feasibility of the project.

Selection of the right site is, of course, critical to the success of any such venture, and therefore the selection process must be thorough, in which every aspect of the project must be taken into consideration. This obviously involves some kind of screening process with a number of steps in which the likely locations are eliminated for one reason or another until the best site is found.

To begin, there should be a process in which all the fields available can be surveyed and parameters established to eliminate those with obvious undesirable qualities. For instance, a

field with difficult access because of severe climatic conditions or one with an insignificant resource should probably be considered undesirable.

Once a list of good candidate areas is defined, other more stringent requirements can be applied to further narrow down the field. At this point, considerations such as remaining oil in place, oil viscosity, permeability, depth of the reservoir, API gravity, pressure, gas in solution, percent oil saturation and percent porosity would be examined and become part of the evaluation process.

Another aspect that must be considered at this point is the mining technology to be used. For oil mining, there are two general types of mining methods available: underground mining for deposits deeper than 1000 feet and surface mining for deposits between 0 and 1000 feet deep. Surface methods include terrace pit, strip mining, and open pit. Of the underground techniques currently available, only the mining for access method appears to have any promise for oil mining, for a number of technical, environmental, economic and safety reasons. After all these options are studied in detail, a decision can be made as to the most feasible and cost-effective methods for the site options available.

Surface mining to recover oil is similar in many ways to surface mining for coal. The reservoir rock, or ore, is generally buried within a sequence of unconsolidated to moderately consolidated sedimentary rock, including sandstone, shale, limestone, dolomite, siltstone, claystone, etc. Recent alluvial deposits of varying thickness generally overlie this sedimentary sequence. Basically, surface mining to recover oil would involve: (1) stripping the overburden down to the top of the ore zone, (2) removing the ore from the open pit, (3) processing the ore to remove the oil, (4) disposing of the spent ore and overburden, and (5) reclaiming the mine and disposal area after the operation has been completed.

Mining for access techniques for oil recovery are a unique blend of two existing and advanced technologies--underground mining and petroleum engineering. Mining for access would involve two or more vertical access shafts from the ground surface to a point below a target reservoir, a system of horizontal drifts to the limits of the reservoir or lease area, and a system of drainage wells drilled from the access drifts into the reservoir above. The well system would be drilled in a fan-like pattern from individual access drifts to penetrate the reservoir in the entire production area with recovery wells. Steam, air or chemical injection or other forms of enhanced oil recovery could be used in conjunction with production wells from the access drifts. Recovered oil from individual wells would be carried to a central collection point in a closed system and ultimately pumped to the ground surface for transportation to refineries.

Starting a Pilot Project

After a site has been selected and a decision made regarding the mining method to be used, the second phase--development of a site-specific pilot mine--can begin. This is perhaps the most important and necessary research and development work for an oil mining venture to identify the problems and resolve them. Figure 2 illustrates the process of developing an experimental oil mine in phases. There are voluminous data from logs, etc. that exist concerning reservoir characteristics. Little data are available concerning formations below the reservoir and would be developed in the field data collection phase. This allows identification of flaws which research and development work can resolve or the project will discontinue due to insurmountable problems. Depending on the mining method, a mine plan must be developed

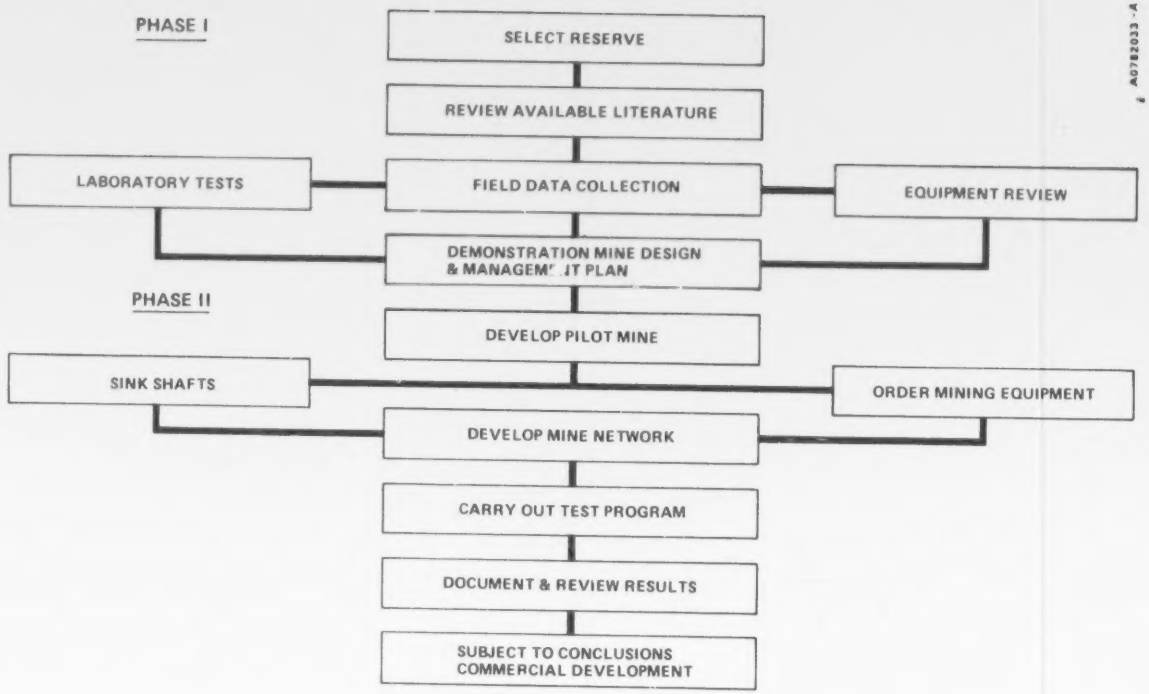


FIGURE 2 DEMONSTRATION PILOT OIL MINE FLOW CHART

and equipment and manpower needs addressed for a reduced-scale version of mining for commercial development--for instance, smaller shafts on a section of the site. Once the pilot mine is in operation, the project can be realistically assessed for its technical and economic feasibility for fullscale commercial development.

Mining should proceed just as it would on a commercial basis. The first step would be to decide the orientation of mining and the deployment within that, and then the production design criteria (rate of mining) can be developed. As mining proceeds, this data can be extrapolated into a three-dimensional time-distance-cost factor. That factor can then be applied to the extent of mine work to simulate its impact and determine production achievements that can be expected for commercial development. At this point a production objective--what rate of production is needed to make the venture pay--can be determined Using the data from the pilot mine, it is a matter of multiplying how many mining units are needed to achieve the established production quota.

STONE & WEBSTER'S INVOLVEMENT IN OIL MINING

The U.S. Department of Energy has recently become interested enough in oil mining to fund a number of studies relating to various aspects of this technology. The DOE commissioned SWEC and Energy Development Consultants to evaluate the technical and economic feasibility of mining for heavy oil, which they did in a report entitled "An Evaluation of Heavy Oil Mining."

The project proceeded under three tasks. The purpose of Task I was to survey the heavy oil reservoirs in the United States amenable to mining and to recommend the five best targets for a demonstration project of mining for heavy oil. The survey was limited to conventional reservoirs containing heavy oil between 10 and 20 degrees API gravity and mobile enough to be distinguished from a tar sand, and within 3,000 feet of the surface.

To select a suitable site, available literature on heavy oil was surveyed and a series of four sets of screening criteria was applied to each reservoir to select those with the most favorable characteristics for mining. The screening process is shown on Figure 3.

The end result of the screening process was the selection of two different fields to be used to draw up theoretical mining ventures--one for extraction of heavy oil using surface mining and one for extraction using mining for access. Both fields are in central California.

These fields were evaluated in terms of the heavy oil resource, the existing technology for recovering it, the economics of development, and the constraints on development. This approach addressed the geologic, engineering and economic realities of each resource or deposit.

The purpose of Task II was to evaluate current available mining technologies for their technical and economic feasibility for recovering heavy oil. Initially, these mining concepts were reviewed: surface mining, extractive mining, and mining for access. Extractive mining was eventually eliminated from further consideration in this study because of economic, safety, environmental, and technical problems that make this method infeasible for oil mining.

Except for the oily surface of the exposed ore in a surface mine, which makes traction more difficult and deteriorates rubber products such as tires, hoses and electrical cable coverings, the surface extractive mining system appeared feasible from technical, environmental and economical considerations. The mining for access method, particularly with thermal

assistance, appears feasible from all technical, environmental and eonomic considerations.

Surface mining involves removing the host rock and processing it to produce oil. A significant environmental problem is disposing of the large amount of waste material produced. There are two kinds of surface mining systems: strip mining and open pit mining (terrace mining).

Within DOE-specified parameters, only six sites (all in California) met the criteria for consideration. These sites were found to be suitable for open pit (terrace) mining only, and therefore stip mining was eliminated as an alternative for oeveloping the hypothetical site.

The mining for access method provides physical entry to an area in close proximity beneath an oil-bearing zone. This mining system consists of shafts and a tunnel network below the ore zone in a more stable strata. Access to the oil-bearing formation is via drilling at selected intervals throughout the tunnel networks.

The safety factor is of utmost importance in this type of mining operation. Once drilling has been completed, oil production is controlled via stand pipes and valves. Oil flows with the assistance of gravity into the tunnel network to the shaft bottom for pumping to the surface, where normal oil processing takes place.

Areas of study under this method included technical feasibility; resource requirements; equipment requirements, reliability and availability; safety; environmental impacts; and economics.

The purpose of Task III was to evalute the two sites selected through the screening process in Task I to determine the technical and economic feasibility of each for recovering oil using mining methods. Both of the fields selected are in central California. The two mining methods to be used in the evaluation--surface extractive mining and mining for access--were selected in Task II, in which all the available technologies were studied.

Surface Mine Study

The field selected for testing of its feasibility for surface extraction was evaluated in a five-step process:

1. A stratigraphic analysis of the area was performed to determine the critical site-specific conditions of the field.

2. A site-specific mine design was developed from these data, and the key parameters for equipment specification were determined, such as bench width and height, haulage distances, and overburden/ interburden ratios.

3. Heavy mining equipment was specified; based on this, the purchase requirements and personnel were determined.

4. A cost engineering effort followed the specification of equipment type and mine infrastructure, and the capital and operating costs for the mining venture were determined.

5. Using the cost engineering data, an economic analysis incorporating discounted cash flow results and sensitivity analyses were performed.

A literature search was conducted to determine critical geotechnical parameters of the field. It lies in an area of rolling hills, and has 9,534 proven acres.

The area chosen for the mine site specific analysis was approximately 3 miles by 1 mile, covering approximately 1,920 to 2,000 acres. The oil

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TYPICAL FLOW CHART OF SELECTION PROCESS

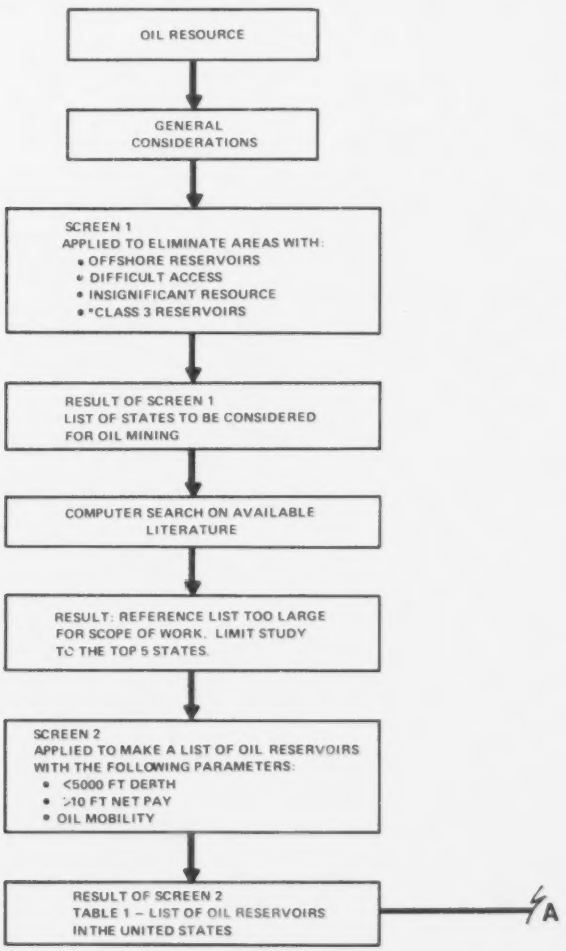
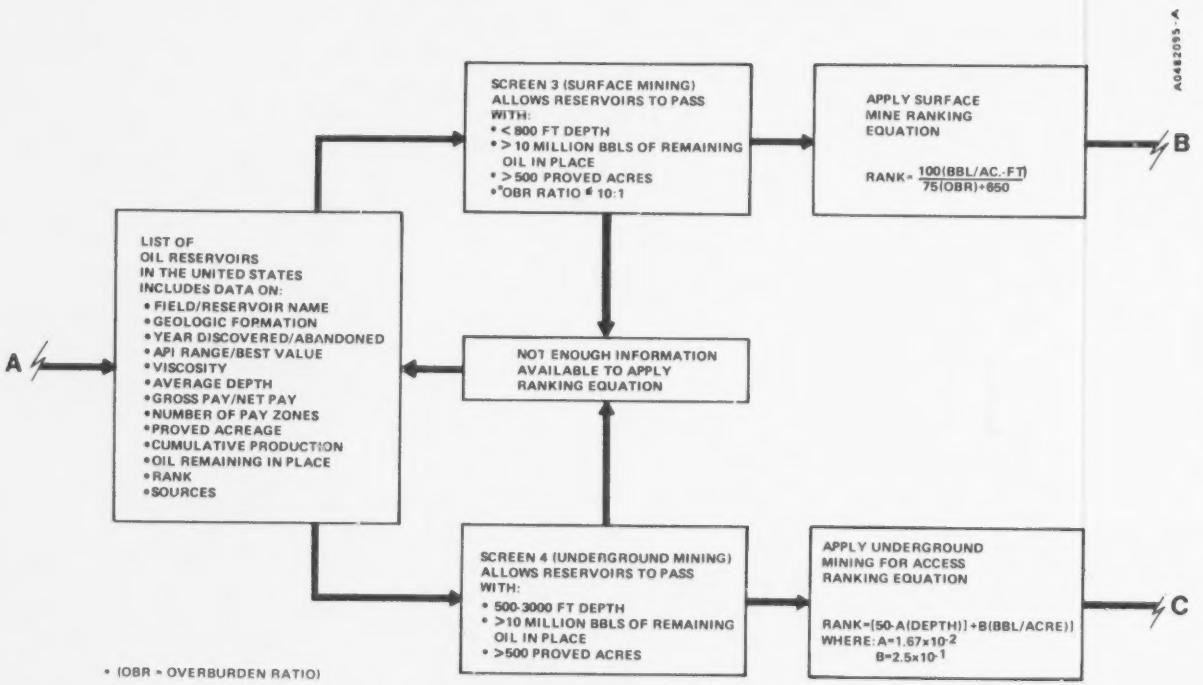

OIL RESOURCE
GENERAL CONSIDERATIONS
SCREEN 1
APPLIED TO ELIMINATE AREAS WITH:
• OFFSHORE RESERVOIRS
• DIFFICULT ACCESS
• INSIGNIFICANT RESOURCE
• *CLASS 3 RESERVOIRS
RESULT OF SCREEN 1
LIST OF STATES TO BE CONSIDERED FOR OIL MINING
COMPUTER SEARCH ON AVAILABLE LITERATURE
RESULT: REFERENCE LIST TOO LARGE FOR SCOPE OF WORK. LIMIT STUDY TO THE TOP 5 STATES.
SCREEN 2
APPLIED TO MAKE A LIST OF OIL RESERVOIRS WITH THE FOLLOWING PARAMETERS:
• <5000 FT DERTH
• ≥10 FT NET PAY
• OIL MOBILITY
RESULT OF SCREEN 2
TABLE 1 – LIST OF OIL RESERVOIRS IN THE UNITED STATES
A
* (AS DEFINED IN 1965 DIETZMAN REPORT – INCLUDES RESERVOIRS WITH FEW DESIRABLE PARAMETERS)

FIGURE 3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SCREEN 3 (SURFACE MINING) ALLOWS RESERVOIRS TO PASS WITH:
• < 800 FT DEPTH
• > 10 MILLION BBLS OF REMAINING OIL IN PLACE
• > 500 PROVED ACRES
• *OBR RATIO ≤ 10:1
APPLY SURFACE MINE RANKING EQUATION
RANK = 100(BBL/AC.-FT) / 75(OBR)+650
B
A
LIST OF OIL RESERVOIRS IN THE UNITED STATES INCLUDES DATA ON:
• FIELD/RESERVOIR NAME
• GEOLOGIC FORMATION
• YEAR DISCOVERED/ABANDONED
• API RANGE/BEST VALUE
• VISCOSITY
• AVERAGE DEPTH
• GROSS PAY/NET PAY
• NUMBER OF PAY ZONES
• PROVED ACREAGE
• CUMULATIVE PRODUCTION
• OIL REMAINING IN PLACE
• RANK
• SOURCES
NOT ENOUGH INFORMATION AVAILABLE TO APPLY RANKING EQUATION
SCREEN 4 (UNDERGROUND MINING) ALLOWS RESERVOIRS TO PASS WITH:
• 500-3000 FT DEPTH
• >10 MILLION BBLS OF REMAINING OIL IN PLACE
• >500 PROVED ACRES
APPLY UNDERGROUND MINING FOR ACCESS RANKING EQUATION
RANK=[50-A(DEPTH)]+B(BBL/ACRE)]
WHERE: A=1.67x10-2
B=2.5x10-1
C
* (OBR = OVERBURDEN RATIO)

FIGURE 3 (CONT.)

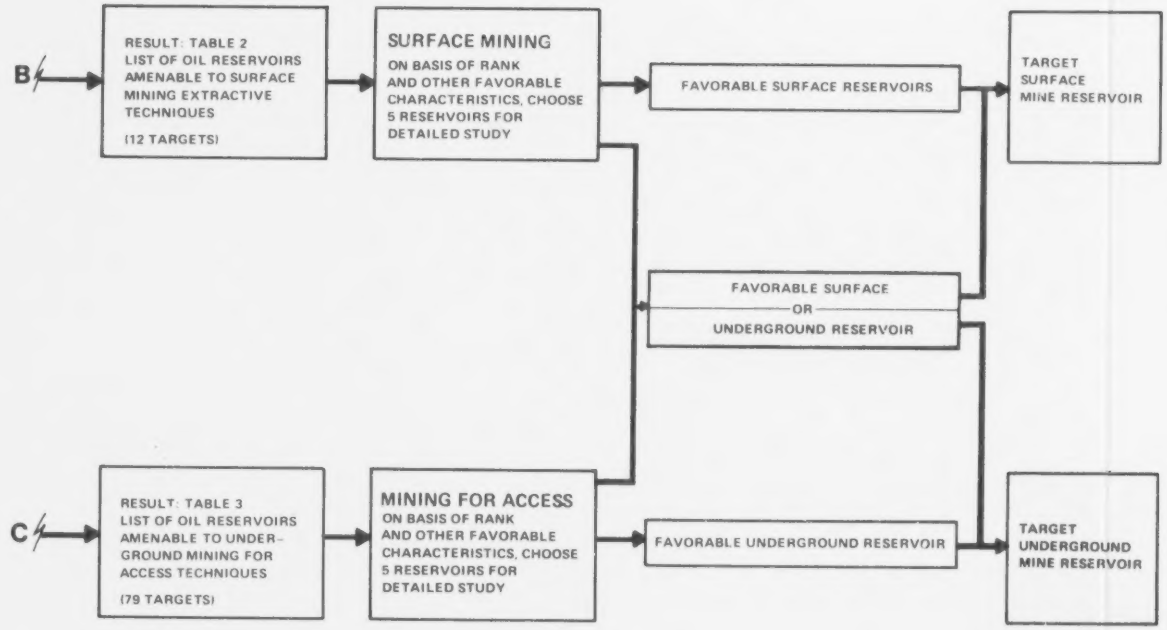

FIGURE 3 (CONT.)

content of the reservoir averages 1,400 barrels per acre-foot in the net pay interval. (0.54 barrels per ton, based on an estimated current oil saturation of 52 percent and a porosity of 35 percent).

The producing horizons occur entirely within one formation, which is composed of productive sand bodies varying from 30 feet to 100 feet thick, separated by mudstones averaging 20 feet thick. The sand bodies occur in a vertically repeated sequence, starting with a basal conglomerate with pebbles from 1/4 inch to 12 inches in diameter, overlain by cross stratified, coarse, poorly sorted sandstone, grading finer upwards into a mudstone composed of fine sandy silt with a minor amount of clay. The top of the reservoir varies from the surface at the east end of the field to as much as 1,500 feet at its southern most end. The trapping mechanism for the heavy oil is predominantly stratigraphic with an updip tar seal and stratigraphic pinchouts.

The oil saturation is an estimated 307,674 barrels per acre with a net pay interval of 220 feet yielding 1,399 barrels per acre-foot in the pay zone. The total oil in place over the 2,600-acre mining target is approximately 800 million barrels. With a required production of 38,150 barrels per day, the life of the 2,600-acre surface mine is estimated to be 60 years.

The oil produced has a gravity of 14 degrees API and a viscosity of 4,000 centipoise, which decreases sharply with temperature. The sulfur content of the oil produced is 1.19 percent with a carbon residue of 6.8 percent.

The mine plan drawn up for this analysis involves extracting oil-saturated ore from the reservoir in a modified open pit/terrace pit operation, backfilling ore and overburden into previously mined areas, and transporting the oil-saturated sands to processing facilities outside the mine. The plan included the initial, production and mature phases of pit geometry based on processing 78,500 tpd of ore to yield 38,150 barrels/day of heavy crude oil on a 20-year production schedule.

The initial waste-to-ore ratio for the outcropping ore body is 2.64:1, the lowest and most economically favorable ratio throughout the life of the mine. Towards the end of production, as the pit expands, the amount of overburden material to be removed increases steadily and the waste-to-ore ratio increases to a 4.0:1 ratio.

In order to initiate the mining operations approximately 36,000,000 tons of overburden is removed in a strip approximately 6,000 feet long in a cross section of roughly 100,000 square feet. By backfilling the mined-out area using the level-haul methodology, preproduction stripping is kept to an absolute minimum and only the stripped material is dumped outside of the pit limits. Further, the ore body is rapidly intersected by this approach, and all of the oil--saturated sand intervals encountered are of positive economic value. The initial cut lengthens to a 3-mile long strip while the mine is advancing outward and downward along the dip angle into the ore body. This long "strip" is sectionalized so that at three separate intervals semi-permanent haul ramps can be established between terraces in order for the ore to be removed from the bottom of the mine while the interburden and overburden waste is hauled on the level terraces around the pit to backfill the previously mined areas.

The total capital investment for such a venture would be approximately $310 million, or an investment of $8,122 per daily barrel. The labor cost per ton of ore mined is $1.17 and is the second largest operating cost center. The largest operating cost center is

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equipment, totaling $2.02 per ton of ore. The total annual operating cost is estimated at $4.35 per ton of ore produced. Assuming a processing cost of $8 per barrel of oil, a total cost per barrel of heavy oil for the surface mining system is approximately $20.

Mining for Access Study

A second field, also in Central California, was selected for evaluation of its potential for recovering heavy oil using underground methods. The analysis proceeded much as for the demonstration surface mine: all technical, environmental and economic aspects associated with this type of a project were examined. In this case however, two variations of the same technology were examined -- mining for access with and without thermal assistance.

The basic reservoir parameters of the reservoir are as follows: The field is very shallow, with the top of the 400-foot reservoir interval located approximately 650 feet below the ground surface. The oil has a gravity ranging from 11° to 13° API, and is very viscous with a viscosity of over 8,500 centipoise at the average borehole temperature of 90° F. The permeability of the reservoir is quite high, with an absolute value of 3,000 millidarcies and a relative permeability of 1,500 millidarcies. The oil content of the reservoir averages 1,600 barrels per acre-ft. in the net pay interval.

For analyses of gravity drainage without thermal assistance, a mine plan was drawn up for five separate gravity drainage producing patterns, and preliminary mine access design was developed for each. Each of the production patterns was described with the well bore spacing, number of access tunnels used, number of production holes drilled, total footage of production holes, and number of access shafts. The objective was to determine which of the five production patterns, ranging in well spacing from 100 feet to 500 feet, would yield the optimum return on investment.

To determine the economic viability of each, the oil production rates were calculated for each project year from reservoir equations describing radial drainage into a production well bore.

Analysis concluded that none of the five well spacing patterns analyzed were economically attractive for the reservoir conditions of this particular field. The viscosity of the crude oil is extremely high at natural reservoir temperatures, implying that the oil production rates by gravity drainage without thermal viscosity modification are exceedingly low.

In all cases analyzed, the total sum of revenue over the 20-year project life equals only a fraction of the initial capital investment. Case I, with a 100-foot well bore spacing and the highest total capital cost, was the only drainage design that approached economic viability. In this case, approximately 81 percent of the initial capital outlay was realized in grossed production over the 20-year project life. The 200-foot production well-spacing earned a total of 31 percent of the initial capital investment.

It was concluded that production by unassisted underground gravity drainage is an inappropriate technology for shallow heavy oil reservoirs: gravity drainage technology does not appear economical in heavy oil fields without thermal assistance to modify the viscosity of the oil to improve its mobility and enhance active drainage mechanisms. For moderately viscous reservoirs (500 cp - 1,500 cp) the analysis further indicates that a dense production well spacing is required in order to achieve a sufficient flow of revenue during the early project life; however, this is weighed against the costs of establishing a high density

of production wells with optimal well spacing. As the viscosity of the produced crude drops, the optimum well bore spacing increases. If the oil in place in this field were reduced to a five centipoise viscosity by steam soak, the optimum production well density would be between 200 and 300 feet (0.9 - 2.0 acres per production well).

The study concluded that for heavy oil gravity drainage without thermal assist it is uneconomical but that it would be worthwhile to investigate the technology for a reservoir with a lighter crude oil (lower viscosity) and a higher oil column height. This analysis supports the conclusions developed in earlier public documents by EDC (1978) and Golder (1978) regarding the economic viability of gravity drainage technology in selected light oil reservoirs that have a substantial oil column height. Operating costs for gravity drainage without thermal assistance were an estimated $0.25 per barrel and $1.00 per barrel, varying with the number of production wells required by the well spacing criterion and the pattern flow rate. Periodically the production holes must be worked over, which incurs a significant labor cost, particularly in reservoirs with highly paraffinic crude oils. Also contributing to the operating costs are materials and supplies for maintaining mine access, the pumping system and heat treating facilities, and the costs of reinjecting formation water. In this particular field it was estimated that three barrels of water would be produced for each barrel of oil, based on historical production data. Although this water is not treated, there is an associated electrical and maintenance cost with its reinjection into the deep water flood formation.

A final component to the operating cost for such a venture is electrical power for the in-mine pumps that transport the oil and water from the collection sump, located in the mine, to the surface heater-treater and separation facilities. Although this pump would have a total brake horsepower (bhp) of less than 100 hp, the maintenance cost for this unit would be high because of suspended particulates in the oil, thereby rapidly degrading seal tolerance. Labor and materials for pump maintenance were considered in the unit barrel operating costs estimated.

Based on the results of gravity drainage without thermal assistance when applied to heavy, shallow crude oil reservoirs, it was concluded that some manner of assistance would be needed to improve production performance. This can be done in two ways:

1. Improve the rate of oil flow by lowering the viscosity of the oil through thermally assisted production.

2. Improve rate of oil flow by increasing the effective oil column height by adding pressure to the oil-producing intervals that are separated by relatively impermeable cap rock.

A variation of steam drive technology can provide both of these production stimulation effects. Therefore, as part of this study several alternative methods were examined for thermally assisting the gravity drainage production mechanism for a heavy crude oil reservoir.

The mine plan for the five cases for gravity drainage was modified to incorporate a specific thermal method to enhance the oil production rate. This field is a good candidate for steam flooding and steam drive, and several such steam injection projects are currently underway by Chevron USA in the same area. These steam injection projects concern both the upper Tulare Sands as well as the Amnicola Zone, and data on the steam-drive techniques most effective for this field were used in this analysis.

The site-specific analysis performed for thermal assistance of an underground gravity drainage project was divided into three basic parts:

- The methods available for thermal assistance were studied before one method was selected for application to this field.
- A preliminary access mine design was developed and the capital costs for the thermal gravity drainage method selected were estimated.
- The economics of gravity drainage with thermal assistance was examined under varying assumptions of total oil recovery.

There are three basic design categories for the available thermal assistance technologies: steam drive, steam injection, and cyclic steam injection. The thermal assist method selected for the evaluation of this field was steam drive using surface injection wells. Surface steam drive was selected because of the low technical risks as compared with the other methods and because successful steam drives have been conducted on several similar fields in the area. In this technique, injection wells are driven from the surface to the producing intervals with steam generating facilities located on skid-mounted steam generators on the surface. This technique is particularly suited to a shallow reservoir such as this one, and the costs of drilling the steam injection wells from the surface are competitive with the costs of installing steam generation underground and injecting from boreholes drilled upward from the access tunnel.

The surface steam drive is applied as with normal steam drive operations in the heavy oil fields of California, with the injection well at the center of a nine-spot square peripheral pattern of producing wells. The wells, however, are drilled from the underground access galleries and differ somewhat from producing wells drilled from the surface in the total amount of lateral area exposed to each producing interval and the lack of required pumping equipment.

The primary factors affecting the thermal efficiency of a steam drive and its economic viability are:

- oil saturation
- reservoir thickness and composition
- steam injection rate
- steam pressure and quality
- oil viscosity

The overall efficiency of steam drive is usually rated by the ratio of oil produced to steam injected (in barrel units) over the life of the project. When calculated in this manner, the theoretical ratio of efficiency for a steam drive, where the energy consumed is equal to the energy produced, is approximately 14 barrels of steam per barrel of oil based on a thermal efficiency of steam generation and distribution of 75 percent.

Research for the study indicated that several drive operations have reported a total recovery of 65 percent of the original oil in place, but recovery generally averages 40 percent to 50 percent of the residual oil saturation. The limitations on recovery efficiency are generally attributed to the following factors:

1. The loss of conformance of the steam to the reservoir oil saturated horizon.
2. A limited ability to vertically sweep the reservoir.
3. The presence of "thief" zones in the reservoirs that cause the steam-to-oil ratio to rise significantly.

4. Significant heat losses from a water column or thermally conductive cap rock above the oil producing zone.

For underground steam generation there are some practical and regulatory problems with locating a steam generator inside an oil mine. Some of the hazards are explosions, steam line ruptures, and the dangers associated with injection of combustion air and handling of flue gases. Several solutions to the permissibility of steam generators in an oil mine have been suggested, including enclosing the entire generator package in a sealed container that would not allow explosive volatiles to leak into the package and would further prevent radiant "hot spots" from forming, causing an external combustion hazard. Combustion air could be compressed at the surface and piped to the steam generator with the exhaust flue gases from the generator mixed with the steam as a miscible flooding agent. There have been reports of success using flue gas as a miscible flooding agent in several types of water flood and drive operations.

The total capital investment for this project would be approximately $184 million dollars to recover 50 percent of the residual oil. The two largest cost centers are production tunnels and production holes. Investment costs range from $2-$5, operating costs range from $4-$6, steam costs range from $12-$16 for a total range of $18-$27 per barrel of oil produced excluding royalties and taxes which would add approximately $9 per barrel, or a total selling price without Return-on-Investment (ROI) of $27-$36 per barrel. The use of steam injection in a reservoir changes the basis for comparing economics not only because each reservoir is different but because the reservoir would be developed on an incremental basis of 3- to 4-year projects rather than a 20-year project. The production for a 18.6-acre pattern would be approximately 1,230,000 barrels for a 4-year project.

The results of this analysis show that the total recovery from gravity drainage without thermal assistance in this viscous crude oil reservoir is insufficient to generate a capital payback equal to the initial capital expenditure. Thus, it is concluded, specifically for this field and in general for the majority of shallow, heavy crude oil reservoirs, that gravity drainage, acting without thermal assistance, yields cash flow profiles that are uneconomical when compared to the initial capital expenditures required for developing the access mine.

It is imperative that a correct set of selection criteria is developed in order to select those reservoirs most amenable to gravity drainage production. Current industry trends in reservoir selection for the gravity drainage technique are toward shallow, heavy crude oil reservoirs since these yield little or no production under primary techniques and are not generally responsive to secondary production methods. It is interesting to note why industry has directed their focus toward the heavy, shallow crude oil reservoirs of California for the gravity drainage technique. The primary reasons for the selection criteria are believed to be:

- Shallow fields are preferred because of perceived limited mining problems for shaft access and tunnel development.

- These reservoirs do not respond to the conventional array of primary and secondary recovery technologies; thus, gravity drainage is erronously assumed to be a candidate technology for production from these fields.

In reality, these concepts could not be more incorrect. The reservoirs amenable to gravity drainage through underground access mines are deep reservoirs that contain light, low viscosity crude oil, and further, these reservoirs should have a high column

of oil in a continuous, saturated interval.

Clearly, the type of reservoir outlined above is in sharp contrast to the heavy, shallow crude oil reservoirs of southern California where the oil columns can be quite small with the oil-saturated sands deposited in narrow, extremely lenticular deposits of fluvial sands.

In view of the above discussion, gravity drainage techniques, when applied to heavy, shallow crude oil reservoirs, must be assisted in some manner to improve production performance. This can be done in two distinct ways:

- Improve the rate of oil flow by lowering the viscosity of the oil through thermal assisted production; and
- The rate of oil production can be improved by increasing the effective oil column height by adding pressure to the oil-producing intervals that are separated by relatively impermeable cap rock.

A variation of steam drive technology can provide both of these production stimulation effects.

However, it should not be taken from these conclusions that gravity drainage as a production technique is generally uneconomical. Contrary to the results obtained from this particular field, gravity drainage is, in general, a very promising production technique for reservoirs that have lost solution drive or water flood energy, and when applied to the proper reservoir, gravity drainage represents perhaps the most economical production technique available for recovering the residual oil saturation.

STONE & WEBSTER'S EXPERIENCE AND CAPABILITIES

SWEC has been providing complete engineering, design and construction services to companies in the United States and many other countries for almost 90 years. Since its formation in the late 1880's SWEC has directed a major portion of its engineering contracting work to research and development in energy resources.

Its activities in the energy field encompass coal handling facilities, coal gasification and liquefaction, oil shale, LNG terminals, wellhead processing, petroleum processing and natural and manufactured gas.

The company's ethylene experience extends over more than 30 years and includes engineering and construction services for a substantial portion of the free world's olefins production. Some 90 ethylene plants for more than 40 clients have been erected, with capacities up to 1.3 billion pounds of ethylene per year.

New Technology

Through the years SWEC has been in the forefront in providing innovative solutions to engineering problems in advanced technology. We have participated in the evaluation and development phases of solar power, substitute fuels for petroleum, new coal combustion techniques, flue-gas desulfurization, energy storage, high-temperature gas turbines, advanced nuclear systems, combined-cycle power plants, development of oil shale processes and other new technologies. Typically, the projects are sponsored by the U.S. Department of Energy (DOE) or the Electric Power Research Institute, and are directed toward early practical application of new concepts.

Current examples of the company's pioneering work are the conceptual design of an Atmospheric Fluidized-Bed Direct Combustion Power Generating Plant for DOE, the North East Coal Utilization Program (NECUP), which is sponsored by SWEC and a group of electric utility companies, and the

SWEC/Petrobras oil shale process evaluation. The first has the potential for capturing coal-contained sulfur in the burning process, thus avoiding the need for a flue-gas scrubber. The second has the potential for burning a coal-derived liquid fuel in direct replacement of petroleum fuel oil as an alternative to converting to burning solid coal. Finally SWEC and Petrobras, the government-owned petroleum company of Brazil have formed an industry team to study that company's successful shale-to-oil process. The team is evaluating applying the process to eastern and western United States oil shales.

Oil Mining

As part of our continued interest in new technologies, it is SWEC policy to stay abreast of any important changes develcping in industry that can become significant improvements over current practice. Through our participation in many projects involving new technologies, SWEC can make informed decisions and can follow with the most appropriate services to its clients. One such technology that shows promise, as an innovation in natural resource extraction, is oil mining. SWEC prepared an evaluation of all phases of oil mining in preparing "Evaluation of Heavy Oil Mining" for the DOE and, we are confident that this technology, particularly when applied to the lighter oil range, could be a key in solving some of our nation's energy problems.

We recognize that any company entering an oil mining venture will encounter a number of major obstacles. First of all, oil mining is a very new technology with no established record of success in the United States. As with any new concept, an element of risk is always involved. This must be addressed with oil mining because of the huge initial capital outlay required to enter into such a venture.

Another concern is the difficulty in obtaining information pertinent to this technology. Very little information is actually available and there is no central data base with a central repository for this type of data. Also, the information is not always as useful as it could be, data concerning the geologic structure below reservoirs is limited or non-existent, and companies with ongoing projects are understandably reluctant to share their data.

SWEC is very aware of these concerns, and we are confident that we have the capabilities and experience to resolve them. SWEC has a complete in-house staff to assemble the necessary team to manage an oil mining project. Our staff includes personnel in mining, geotechnical, environmental, permitting, economics, and processing. We have conducted many feasibility studies and participated in projects involving new technology.

As previously stated, SWEC has prior experience in evaluating oil mining. In keeping with our continuing interest in new and promising technologies, SWEC is one of the first major engineering firms with experience in oil mining evaluation on a site specific basis, having just completed the latest study in this field, for the Department of Energy. Also, through Stone & Webster, Incorporated we have affiliate companies actively engaged in the oil industry. Dynawest, of Toronto, Canada, is developing a "standard" design of a 500 bbl/day heavy oil pilot plant that could be easily adapted to the specific requirements of a client and to specific site conditions. Saw Drilling, based in Texas, provides contract drilling services to oil and gas operators. Enterprise Resources, Inc. owns and operates gas properties in Texas.

Multi-Company Approach

Based on SWEC's prior experience in oil mining feasibility studies and on

our understanding of the risks involved in a new technology, we have devised what we believe to be a possible approach to an oil mining venture. We call it the multi-company approach, and it means simply that several companies, rather than just one, enter into a cooperative venture in which each entity contributes either the resources, expertise or financial backing necessary for such a project. The suggested approach is as follows: SWEC would arrange a cooperative venture with a resource or lease owner and an oil company willing to supply the financial backing. SWEC would then implement and manage the project, thus contributing the technical expertise and sound management practices gained through our extensive project experience.

Mining Experience

SWEC has participated in a wide range of mining and civil projects which have given us the expertise and experience to evaluate mining technologies for possible adaptation to oil mining. For Western Fuels-Utah, Inc., SWEC provided the engineering design and construction management for a combined overland belt conveyor and railroad transportation system in northwestern Colorado and Utah. A 3.5-mile long overland conveyor and 35-mile long electric captive railroad will connect an underground coal mine near Rangely, Colorado, with a proposed 800 MW fossil-fuel complex near Bonanza, Utah. The project also included preliminary engineering and environmental studies leading to selection of, and application for, the transportation corridor.

In a project for SUNEDCO, SWEC supplied conceptual engineering services for the surface facilities on the proposed Sage Point-Dugout Canyon Mine in Utah. Conceptual engineering included two mine portal facilities, central facilities, material handling systems, road and railroad design and necessary surface support buildings.

For Wyodak Resources Development Corporation, the project included the engineering and design services for a truck load-out facility at the Wyodak Mine. In addition, SWEC rebuilt the conveyor system.

SWEC completed a technical and economic study covering the development of Arkansas Lignite for Arkansas Power & Light. The study was based on two 500 MW lignite-fueled plants and included mines, transportation, power plants, waste handling and an environmental assessment.

For the U.S. Bureau of Mines (Department of Energy), SWEC designed a hydraulic transport research facility to test transport of large-lump coal by pipeline. Tasks included the establishment of design criteria, engineering specifications and consulting during construction.

For Lakhra Coal Project (Pakistan) for U.S. Agency for International Development (USAID), SWEC reviewed several previous mining studies to prepare up-to-date mining cost estimates for two surface and one underground operation. Tasks included optimizing local labor and capital, developing labor intensive but cost effective mining schemes and preparing manpower and equipment estimates as well as mining operating cost.

The DOE recently commissioned SWEC to prepare a study of heavy oil mining in the continental United States. The study was conducted to define oil fields suitable for heavy oil mining within certain parameters laid down by the DOE, e.g., depth, area and estimated oil remaining in place. Various methods of mining were considered and specific sites were selected to prove the feasibility of such mining projects. SWEC's Denver Operations Center (DOC) divisions involvement included geotechnical, cost estimating, environmental and permitting in addition to SWEC's mining engineering staff.

OIL MINING

Testimony to the Subcommittee on Energy and Mineral Resources

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March 2, 1984

MR. CHAIRMAN AND MEMBERS OF THE SUBCOMMITTEE ON ENERGY AND MINERAL RESOURCES:

The following comments pertain to the subject of petroleum mining.

At this time the United States has reached an important and critical stage in the extraction of energy resources. We have passed through a period of almost constantly rising production of petroleum into a period of nearly constant or slightly declining domestic production. On the world scene we have weathered a period of rising energy costs and restricted supplies, and we are now experiencing stable to falling prices and apparently abundant petroleum supplies. The danger here is that a significant proportion of our citizenry may begin to believe that conservation is no longer vitally important because there is plenty now, and we will use renewable or alternative sources in the future. The future may belong to renewable energy sources, but we are not there yet and just when we will get there is very uncertain. Meanwhile, we avail ourselves of any and all reasonable ways of securing additional energy supplies.

The petroleum industry has developed numberous sophisticated techniques to enhance the recovery of crude oil and natural gas from reservoir rocks. Reservoir stimulation procedures such as hydrofracturing are designed to improve the production characteristics of the rock surrounding the well bore, and to increase the ease of fluid flow to the well. Secondary and tertiary recovery operations, such as water flooding and steam flooding respectively, are employed to maintain reservoir pressures, free petroleum from pores, and aid movement of the fluid through the reservoir.

In spite of continuing research and many active enhancement programs, much petroleum remains in so-called depleted reservoirs. There are numerous reasons for this. For example, the required enhancement program may not be cost effective or the rock characteristics are such that available techniques are not applicable. Perhaps the geology of a field or pool is unfavorable for an enhancement program. Another possibility is that the way in which a field was developed and produced may limit the success of an enhancement attempt. In any event, other approaches such as mining may be worthy of consideration.

Although I am not an expert in mining technology, it is my opinion that mining is a viable approach to petroleum extracting in some cases. The minimum requirements that a reservoir must meet appear to be (1) a significant quantity of petroleum produced at a rapid rate, (2) a location at relatively shallow depths below the surface, and (3) associated rocks suitable for shaft support. To these three might be added a relatively simple geologic situation in which few faults or folds, for example, occur.

The actual quantity of past production that will make a reservoir an attractive candidate for mining will vary because of many economic and technical factors, however, a rapid production rate is favorable because reservoir pressures may have been reduced at a greater rate than that optimum for maximum extraction. Depth considerations are important because of construction costs and possible surface effects. Competent rocks are important from technological and safety perspectives. Simple geology should reduce the number of drainage shafts and favor resource control and collection.

My experience has been primarily with the so-called Lima Field of Northwestern Ohio. That field, which actually extends into Indiana, was developed in the 1880's and quickly depleted by rapid pumpage and dense well spacing. In spite of the large volumes of oil and gas extracted from the field, it is probable that great quantities of oil remain which could be removed by some type of mining operation. The result of conventional enhancement techniques are difficult to predict because of the presence of literally thousands of improperly plugged and abandoned old wells that cannot now be adequately located. These wells may leak as the reservoir is repressurized, making resource control difficult at best and probably impossible.

Other reservoirs with similar characteristics, geology, and production histories can be found. Mining may be an alternative method of production that results in extraction of more of the remaining oil and thereby better utilization of a very valuable resource. This is certainly a positive aspect. Safety questions must be considered, but they do not appear to be overriding problems. I suggest that petroleum mining is an attractive alternative production technique that needs to be carefully studied in relation to some actual fields.

Trenton Formation (Middle Ordovician) of Northwestern Ohio: Possible Target for Petroleum Mining[1]

RONALD D. STIEGLITZ[2]

ABSTRACT

Interest in mining petroleum has been renewed recently as prices climb, supplies decrease, and the need to improve recovery is recognized. The Trenton Formation in northwestern Ohio is a carbonate reservoir which was developed during the 1880s and depleted shortly after the turn of the century. The formation appears to satisfy at least the minimum requirements of significant past production, relatively shallow depth, and associated competent rock to support shafts, and therefore a detailed analysis may be justified.

INTRODUCTION

Energy problems facing the world today have spawned some innovative hydrocarbon extraction techniques and strategies. One problem of long-standing concern is that of more efficient and complete energy resource extraction. Generally, removal of a larger percentage of a fossil fuel not only increases profits but also results in increased supplies and improved resource utilization.

The petroleum industry in particular has pursued active research and application programs to improve extraction methods. Numerous reservoir stimulation techniques as well as secondary and tertiary recovery operations have been developed and used to remove more of the total in-place oil. Despite the best efforts in these areas, extraction commonly is not greater than 40%. Some estimates suggest that over half of the crude oil ever discovered is still in place.

MINING OF PETROLEUM

If reservoirs cannot be pumped to yield all of their contained crude oil by water flooding, chemical treatment, or heat, other approaches may be worthy of consideration. One such option may be the mining and draining of depleted reservoirs. The idea is not new, but it has received renewed consideration by some foreign countries and the U.S. Bureau of Mines. Maugh (1980) summarized recent developments. Many methods or combinations of methods suggested to mine petroleum reserves range from actual removal and washing of the reservoir rock to in-place drainage with or without a driving agent of some type. The purpose of this report is to call attention to a reservoir that may be an attractive target and therefore deserve further evaluation.

Provisionally, it would appear that to be considered for possible mining operations, a reservoir must meet at least three requirements. First, it must have a significant record of production. The actual amount will vary according to economic and geologic factors. Second, it must not lie at too great a depth because of cost and perhaps heat considerations. Conversely it might be suggested that it should not be too shallow because of possible surface effects although this would not appear to be a problem for most oil reservoirs. Third, the reservoir should be associated, perhaps best underlain, with rock suitable for the driving and support of shafts. The Trenton Formation in northwestern Ohio may satisfy these requirements (Fig. 1).

HISTORY OF OIL PRODUCTION

Natural gas in commercial quantities was first produced from the Trenton Formation near Findlay, Ohio, in November 1884 (Orton, 1888). Although most early wells produced both gas and oil, the original goal was gas and not until a year later in November 1885 was the first well recorded that was drilled for oil (Orton, 1888). The following spring the true development of the Findlay oil field began. The important oil field at Lima in Allen County was tested in the spring of 1885 but development was delayed until the following spring. Immediately gas and oil were being found in variable amounts in most northwestern counties of the state. The northwestern Ohio oil field was perhaps the first truly large field discovered in North America. Production rose rapidly from negligible quantities in 1885 to over 1 million bbl in 1886 to nearly 10 million bbl in 1888 (Bownocker, 1903). The field reached peak production of over 20 million bbl in 1896, little more than 10 years after the initial discoveries, but production declined equally as rapid to below 10 million bbl in 1906 and 1 million bbl in 1934 (Alkire and others, 1951).

The producing area in Ohio (Fig. 2A) was outlined for the most part before 1900 and has expanded little since. Main production came from a curving belt from Lucas and Ottawa Counties in the north to Van Wert and Mercer Counties in the southwest. The productive belt continues westward into Indiana. The main production was centered in Wood, Hancock, and Allen Counties. Isolated outliers of production were located east and west of the main trend (Fig. 2A).

Drilling has continued through-

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FIG. 1—Location map of northwestern Ohio.

out the area to the present with periodic spurts of increased activity. Recently, interest has again been generated primarily because the Trenton Formation is a shallow target. Cumulative production and the total number of wells drilled are difficult to determine accurately. Buehner (1971) estimated a cumulative production of 483 million bbl of oil from 100,000 wells for the entire Ohio-Indiana area. In Ohio, production has been approximately 380 million bbl.

GEOLOGY OF TRENTON FORMATION

Regionally most of northwestern Ohio is part of the Indiana-Ohio platform located between the Appalachian basin on the east and the Michigan basin on the northwest (Green, 1957). Within the area, a prominent monocline, with associated faulting, known as the Bowling Green structure trends slightly west of north from Harden County to Lucas County. Even generalized structure maps clearly show the dip of the rocks into the basins and the trend of the Bowling Green structure (Fig. 2B). Some highest yielding wells were apparently associated with the structure in Wood and Hancock Counties. Janssens and Stieglitz (1974) discussed the lithologic and stratigraphic relations of the lower Paleozoic rocks of northern Ohio and their implications for the development and history of the Findlay arch.

The Trenton Formation in the area is composed of fossiliferous limestone with gray to black argillaceous partings (Stieglitz, in press). Thickness of the formations ranges from approximately 60 ft (18 m) in the southeast to more than 300 ft (91 m) in the north (Fig. 2C). The thickness increases rapidly northwestward across Hancock, Seneca, and Sandusky Counties. Over much of the area of past production, the formation is between 150 and 300 ft (46 and 91 m) thick. Commonly the uppermost few feet or tens of feet of the rock has been dolomitized. Along the Bowling Green structure and in other scattered areas most or

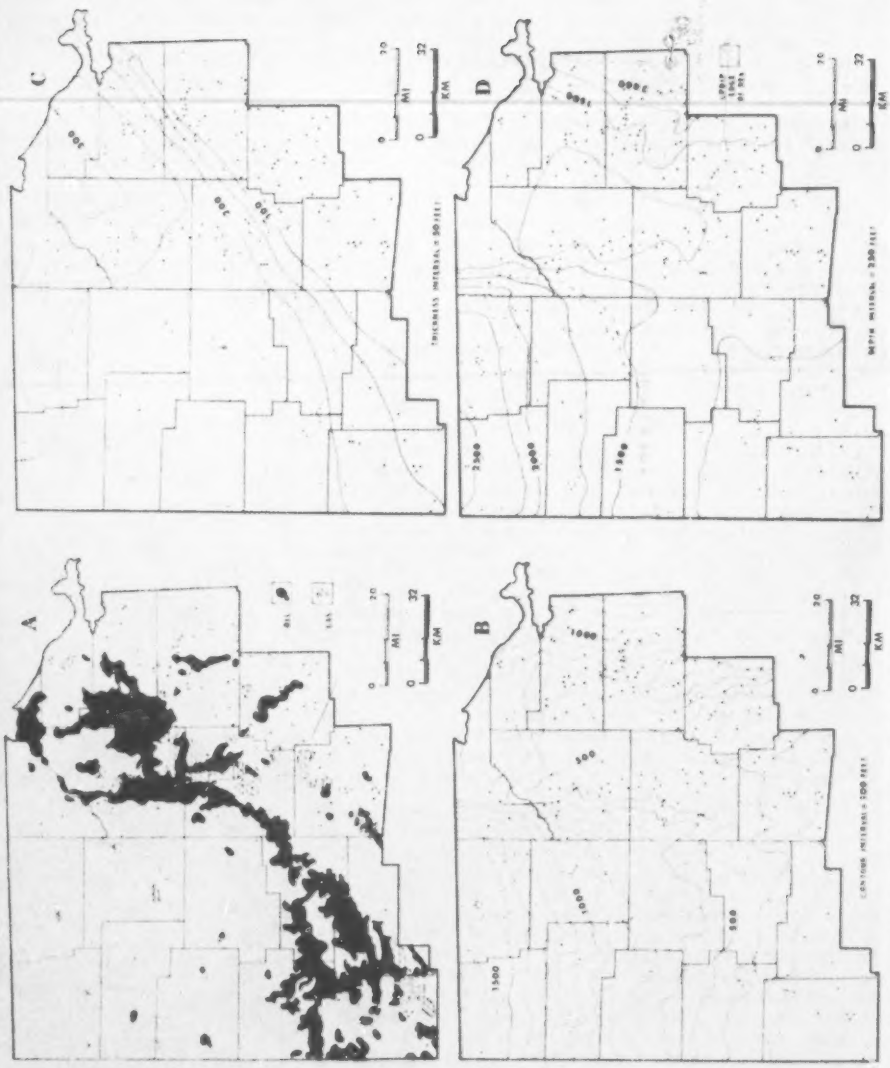

FIG. 2—A, generalized area of Trenton oil and gas production. B, generalized structure on top of Trenton Formation. C, thickness of Trenton Formation. D, depth to top of Trenton Formation.

all of the formation has been dolomitized. White sparry dolomite may indicate the presence of secondary porosity formed by fracturing and solution (Stieglitz, 1975). Other evidence of large-size porosity was supplied by the records of early wells cited by Orton (1888) and Bownocker (1903). Some drilling tools were reported to have fallen several feet or to have become stuck in "crevices." Production histories of individual wells, some of which showed copious production whereas nearby wells produced little or no oil, also suggest large openings, and secondary porosity.

In northwestern Ohio the Trenton Formation is overlain by thick undifferentiated Upper Ordovician rocks (fig. 3). These beds, which for the most part consist of dark shales and siltstones, formed the cap on the porous Trenton carbonate rocks. Fine-grained dense Black River carbonate rocks underlie the Trenton Formation in the entire area.

Over much of the producing area the Trenton Formation is found at depths less than 1,300 ft (396 m; Fig. 2D). It is deepest in northern Williams County near the Michigan basin. The formation is less than 1,200 ft (366 m) below the surface in Mercer, southern Van Wert, and eastern Auglaize Counties, and also in central Wood and Hancock Counties along the crest of the Bowiing Green structure. Westward across the structure, depth to the Trenton increases rather abruptly to nearly 1,700 ft (518 m) in western Wood County. Eastward the depth increases more gradually over a broad, uniform area.

DISCUSSION

The Trenton Formation in northwestern Ohio appears to have potential for the extraction of residual oil by mining and drainage techniques. Total oil production from the field was significant and some individual wells yielded many thousands of barrels. For example, the following are some of the large wells described by Orton (1888) and Bownocker (1903). The Corry well drilled in 1887 in Sec. 16 of Liberty Township, Hancock County, yielded an estimated 1,500 bbl/day during the first week and 350 bbl/day after 6 months. In Liberty Township, Wood County, the Ducat well drilled in about 1887 flowed uncontrolled for 48 hours before yielding 10,000 bbl/day. In Sandusky County the Kirkbride well drilled in Sec. 19 of Madison Township in 1894 flowed uncontrolled the first day and produced for at least 10 years. Large wells were also completed in Sec. 18 of Perry Township, Allen County, where some produced over 2,700 bbl/day. Although length of production and total oil produced are not available for most of these wells, they indicate something of the character of the reservoir early in its development. These large wells are, however, unusual and most of the oil was produced from wells yielding 10 to several hundreds of barrels per day. Buehner (1971) gave rather low average recoveries of 840 bbl/acre (336 bbl/ha.) in Ohio with maximum recoveries ranging from 2,000 to 9,000 bbl/acre (800 to 3,600 bbl/ha.) along the eastern margin of the Bowling Green structure. What recoveries may have been if modern stimulation and production techniques had been used is speculative. The depth to the Trenton Formation is well within limits of applicability of mining operations. At its deepest point in northwestern Ohio the formation is only 2,600 ft (793 m) below the surface and that is far from the main oil producing area. Along the main production trend the formation generally lies less than 1,500 ft (457 m) below the surface.

Coherent and competent rock below the reservoir rock also appears to be generally available. Over most of the area, production was from a coarsely crystalline dolomite comprising the uppermost part of the formation. Early production was nearly limited to the top 50 or 60 ft (15 or 18 m) of the formation. Later, deeper drilling located additional producing zones as much as 150 ft (46 m) below the Trenton top. These deeper zones again seem to be restricted to the vicinity of the Bowling Green structure. In most areas, 200 ft (61 m) of strong limestone underlies the dolomite followed by a thick sequence of dense Black River carbonate rock. Fracturing, solution, and perhaps faulting may be present to much greater depths locally and may hinder mining and collection operations in some areas. Much of this alteration seems to be the result of rock flexing along the trend of the Bowling Green structure and smaller related features and as such may be concentrated in the upper part of the Trenton–Black River sequence. Careful evaluation of geophysical logs or modern geophysical techniques may be able to clarify the extent of the fracturing.

Conventional secondary and tertiary recovery techniques have not been employed in the area so far as I know because of the large number

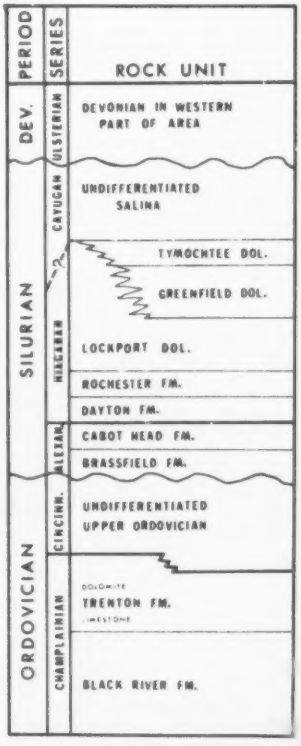

FIG. 3—Generalized geologic column of northwestern Ohio. Silurian section modified from Janssens (1977).

of wells drilled into the reservoir. Many early wells cannot be located and no doubt most were abandoned without having been properly plugged. Such an area with thousands of potentially leaky wells would be of great concern for secondary recovery operations. The overlying Silurian dolomites which form the bedrock over much of the area are important ground-water aquifers (Norris and Fidler, 1971). Movement of oil or brine into these rocks through old wells is a real possibility if attempts were to be made to repressurize the Trenton.

Alternative techniques such as mining may be better suited to this and other similar shallow depleted fields. Perhaps a market can be found for the limestone removed from the tunnels during the development stage. The Black River carbonate rocks, for example, may be pure and of high quality. Not only could this help to defray part of the cost of the operation, but it could also reduce the need to expand surface quarrie—which might be an additional environmental bonus. A detailed analysis of the potential of the Trenton Formation in northwestern Ohio may be justified.

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